U.S. DEPARTMENT OF ENERGY

OFFICE OF POWER TECHNOLOGIES

CLEAN POWER FOR THE 21ST CENTURY

Documentation for

FY2003 GPRA Metrics

Office of Power Technologies
Energy Efficiency and Renewable Energy
U.S. Department of Energy

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SECTION I

Technology Data Sheets:
Summary of the FY 2003 Benefits Analysis

This report is broken into two sections: a summary section providing an overview of the benefits analysis of OPT technology R&D programs, and a detailed section providing specific information about the entire GPRA benefits process and each of the OPT programs.

The following pages report the data sheet summaries for the Office of Power Technologies (OPT) sector submissions for FY 2003 GPRA Benefits Analysis. Each technology data sheet includes the basic program assumptions, the methodology of the GPRA analysis, and a summary of the benefits results.

FY2003 GPRA METRICS
SOLAR PROGRAM

GPRA 2003 Program Assumptions

Commercialization Dates

Photovoltaics are commercial; CSP troughs are commercial; CSP dishes are commercial prototype; CSP Power Tower is refined prototype; domestic water heaters and pool heaters are commercial

Capital Cost (constant 1999 dollars)

	2003	2004	2005	2006	2007	2010	2015	2020	2025	2030
PV ($/kW)	4,990	4,630	4,280	4,020	3,750	2,960	2,300	1,740	1,420	1,100
CSP ($/kW$_{nameplate}$) CSP ($/kW$_{peak}$)	3,145 1,475	2,735 1.385	2,330 1,295	2,385 1,230	2,440 1,160	2,605 965	2,565 950	2,525 935	2,525 935	2,525 935
DHW Systems ($/System)	2500									
Pool Heating Systems ($/System)	4000									

O&M Cost ($/kW-yr)

	2003	2004	2005	2006	2007	2010	2015	2020	2025	2030
PV ($/kW-yr)	13.0	12.5	12.0	12.0	11.5	10.5	9.0	9.0	8.6	8.4
CSP ($/kW-yr)	67.0	40.5	31.5	23.0	24.5	25.5	30.0	27.5	25.0	25.0
DHW Systems ($/System-yr)	30									
Pool Heating Systems ($/System-yr)	0									

Technology Performance Indicators

	2003	2004	2005	2006	2007	2010	2015	2020	2025	2030
PV- CF (%)	20.6	20.6	20.6	20.6	20.6	20.6	20.6	20.6	20.6	20.6
CSP- CF (%)	43.6	43.8	44.0	48.2	52.4	65.0	71.0	77.0	77.0	77.0
DHW – Electricity Savings	2750 kWh/yr									
Pool Heating – gas savings	1600 therms									

Product Lifetime (years): 30

Other Assumptions: Technology data for PV and CSP is taken from *Renewable Energy Technology Characterizations* (this report is currently being updated and the values may change). Data is weighted by the following factors: PV- 25% Central Station and 75% Buildings and Structures in 2000, changing to 35% Central Station and 65% Buildings and Structures by 2015, and CSP-100% power tower. Technology data for Solar Buildings is taken from Program support documentation.

GPRA 2003 Analysis

Methodology:

The solar penetration estimates consists of three components:

1) Green Power Markets: The Green Power Market Model was used to project PV and CSP capacity installed to meet the demands of green markets. These estimates were then explicitly included in the NEMS runs. Projections for total green market potential are taken from NREL, *Growing the Green Power Market: Forecasting the Impacts of Customer Demand for Renewable Energy* (NREL/TP-620-30101). Also included in the green segment are projections of the Million Solar Roofs initiative within the PV program, which projects an additional 4.6 GW by 2020, and the Southwest initiative within the CSP program, which projects an additional 1.3 GW by 2020.
2) NEMS: The National Energy Modeling System (NEMS) was run to estimate market penetration into the competitive bulk power marketplace for CSP and PV. NEMS, as run by LBNL for the GPRA analysis, incorporates technology cost and performance projections as taken from the *Renewable Energy Technology Characterizations*, published by DOE and EPRI in 1997. As NEMS projections are not made for 2020-2030, linear extrapolations for the least-cost portion of the capacity projection, based on the 2015-2020 increment, are used. Details on the NEMS modeling activity are provided elsewhere in this documentation.
3) The solar buildings penetration estimate was developed using a market penetration model that takes current levels of installed capacity and current market growth rates, and projects future utilization using market s-curve formulations.

Note: The results presented represent the amount of capacity projected to be installed in the years beginning 2003 (i.e., the benefit of program activities conducted during FY 2003).

GPRA 2003 Benefits Summarv

	2003	2004	2005	2006	2007	2010	2015	2020	2025	2030
Cumulative Penetration (above GPRA baseline- 0.03 PV and 0.33 CSP)										
PV + CSP (GW)	0.08	0.15	0.25	0.40	0.55	1.50	4.25	7.85	11.5	14.5
DHW (thousands of systems)	10	20	35	50	65	125	360	835	1,950	3,500
Pool Heater (thousands of systems)	25	55	85	115	150	255	475	690	1,130	1,455
Annual Penetration										
PV + CSP (GW)	0.08	0.08	0.10	0.15	0.15	0.30	0.55	0.70	0.75	0.60
DHW (thousands of systems)	10	11	12	14	15	22	47	95	223	309
Pool Heater (thousands of systems)	26	28	30	31	32	36	44	44	88	65

	2003	2004	2005	2006	2007	2010	2015	2020	2025	2030
Energy Metrics										
Total Primary Energy Displaced (Quads/yr.)	0.01	0.02	0.02	0.03	0.04	0.08	0.20	0.35	0.50	0.70
Direct Natural Gas Displaced (billion cu. ft./yr.)	5.25	11.0	16.5	22.5	28.5	56.5	130	235	350	475
Direct Petroleum Displaced (million barrels/yr.)	0.03	0.06	0.05	0.08	0.09	0.06	0.20	0.55	0.80	1.10
Direct Coal Displaced (million short tons/yr.)	0.02	0.06	0.10	0.15	0.30	0.75	1.70	3.25	4.90	6.45
Total* Displaced Barrels of Oil Equivalent (million barrels/yr.) (*sum of gas, oil, and coal)	1.00	2.15	3.30	4.50	6.00	12.5	28.0	53.5	82.0	115
Financial Metrics										
Energy Cost Savings (billions 1999$/yr.)	0.04	0.05	0.10	0.15	0.20	0.35	0.80	1.50	2.45	3.60
Non-Energy Cost Savings (billions 1999$/yr.)	0.00	0.00	0.00	0.01	0.01	0.02	0.05	0.07	0.09	0.10
Cumulative Consumer Investment (billions 1999$/yr.)	0.50	1.00	1.50	2.10	2.75	5.75	12.5	20.0	29.0	37.0
EERE Expenditures (millions 1999$/yr.)	93.0	93.0	93.0	Assume Level Funding				93.0	93.0	93.0
Other Govt. Expenditures	Negligible									
Private Sector Expenditures	$46 million cost-share in 2001 (per SMS)									
Environmental Metrics										
Carbon Emissions Displaced (MMTCE/yr.)	0.10	0.20	0.35	0.45	0.60	1.35	3.10	5.90	9.15	12.5
SO_2 Displaced (Metric tons/yr.)	0.00	0.01	0.01	0.01	0.01	0.03	0.05	0.09	0.15	0.20
NO_x Displaced (Metric tons/yr.)	0.00	0.00	0.01	0.01	0.01	0.02	0.03	0.06	0.09	0.10

FY2003 GPRA METRICS
BIOPOWER

GPRA 2003 Program Assumptions

Commercialization Dates
Initial Prototype (Gasification): 1995 Pacific International Center for High technology/Institute of Gas Technology
Commercial Prototype (Gasification): not yet produced
Commercialization: Co-firing for several boiler types is now available

Capital Cost ($/kW) (constant 1999 dollars)

	2003	2004	2005	2006	2007	2010	2015	2020	2025	2030
Gasification	1,750	1,700	1,650	1,610	1,580	1,460	1,350	1,260	1,180	1,110

O&M Cost ($/kW-yr) (includes feedstock cost of $2.50/GJ)

	2003	2004	2005	2006	2007	2010	2015	2020	2025	2030
Gasification	207	206	205	205	205	205	196	187	181	175

Technology Performance Indicators

	2003	2004	2005	2006	2007	2010	2015	2020	2025	2030
Capacity Factor (%)	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0
Heat Rate (kJ/kWh)	9220	9220	9220	9220	9220	9220	8720	8220	7900	7580

Product Lifetime (years): 30
Other Assumptions: Technology data from *Renewable Energy Technology Characterizations* (this report is currently being updated and the values may change). Gasification systems are modeled in NEMS and characterized here. Co-firing systems generally cost $200-300/kW of retrofitted capacity.

GPRA 2003 Analvsis

Methodology:
The biopower penetration estimate consists of three components:
1) Green Power Markets: The Green Power Market Model was used to project biomass gasification and direct-fired steam turbine capacities installed to meet the demands of green markets. These estimates were then explicitly included in the NEMS runs. Projections for total green market potential are taken from NREL, *Growing the Green Power Market: Forecasting the Impacts of Customer Demand for Renewable Energy* (NREL/TP-620-30101).
2) NEMS: The National Energy Modeling System (NEMS) was run to estimate market penetration for biomass gasification-based electricity generation into the competitive bulk power marketplace. Least cost direct-fired biomass generation is assumed to be cogeneration, which is not a part of the biopower program, and is reported under the DER program. Least cost co-firing is analyzed in an exogenous model detailed below. NEMS, as run by LBNL for the GPRA analysis, incorporates technology cost and performance projections as taken from the *Renewable Energy Technology Characterizations*, published by DOE and EPRI in 1997. As NEMS projections are not made for 2020-2030, linear extrapolations, based on the 2015-2020 increment, are used. Details on the NEMS modeling activity are provided elsewhere in this documentation. Additional projections of least cost gasification-based generating capacity were added to the NEMS portion, based on a review of the ADL report, *Aggressive Growth in the Use of Bio-derived Energy and Products in the United States by 2010*.
3) Co-firing: Current co-firing projections are based on a review of the ADL report, *Aggressive Growth in the Use of Bio-derived Energy and Products in the United States by 2010*. The use of wood co-firing in coal power plants is frequently a cost-effective option. A survey of potential locations for co-firing retrofits was developed and used for the co-firing capacity projections in this analysis.

Note: The results represent the amount of capacity projected to be installed in the years beginning 2003 (i.e., the benefit of program activities conducted during FY 2003). Penetration does not include biomass cogeneration, which is included in DER metrics.

GPRA 2003 Market Penetration Results (thousands of MW)

	2003	2004	2005	2006	2007	2010	2015	2020	2025	2030
Cumulative Penetration (above GPRA baseline)										
Without EERE	1.60 (GPRA baseline)									
With EERE	0.40	1.35	2.30	3.25	4.15	7.00	8.75	10.5	12.5	14.0
Annual Penetration										
Without EERE		0	0	0	0	0	0	0	0	0
With EERE	0.40	0.55	0.65	0.75	0.75	0.95	0.35	0.35	0.40	0.30

FY2003 GPRA METRICS
BIOPOWER

GPRA 2003 Benefits Summary

	2003	2004	2005	2006	2007	2010	2015	2020	2025	2030
Energy Metrics										
Total Fossil Energy Displaced (Quads/yr.)*	0.03	0.10	0.20	0.25	0.35	0.55	0.70	0.80	0.95	1.05
Direct Natural Gas Displaced (billion cu. ft./yr.)	0.90	2.75	4.75	6.90	11.5	24.5	32.5	33.0	41.0	49.5
Direct Petroleum Displaced (million barrels/yr.)	0.07	0.15	0.10	0.15	0.20	0.10	0.20	0.30	0.35	0.40
Direct Coal Displaced (million short tons/yr.)	1.50	5.10	8.75	12.5	16.0	26.0	31.5	38.0	44.0	49.5
Total* Displaced Barrels of Oil Equivalent (million barrels/yr.) (*sum of gas, oil, and coal)	5.15	17.0	29.5	41.5	53.5	88.0	110	130	150	170
Financial Metrics										
Energy Cost Savings (billions 1999$/yr.)	-0.05	-0.10	-0.20	-0.30	-0.40	-0.70	-0.85	-1.00	-1.15	-1.30
Non-Energy Cost Savings (billions 1999$/yr.)	0.01	0.03	0.05	0.07	0.09	0.15	0.15	0.15	0.20	0.20
Cumulative Consumer Investment (billions 1999$/yr.)	0.15	0.50	0.80	1.10	1.45	2.65	3.60	4.05	4.65	5.20
EERE Expenditures (millions 1999$/yr.)	40	40	40	Assume Level Funding				40	40	40
Other Govt. Expenditures (millions 1999$/yr.)	Negligible									
Private Sector Expenditures (millions 1999$/yr.)	$20 million cost-share in 2001 (per SMS)									
Environmental Metrics										
Carbon Emissions Displaced (MMTCE/yr.)	0.80	2.75	4.70	6.65	8.60	14.0	17.0	20.5	23.5	27.0
SO_2 Displaced (Metric tons/yr.)	0.02	0.05	0.09	0.10	0.15	0.25	0.30	0.35	0.45	0.50
NO_x Displaced (Metric tons/yr.)	0.02	0.05	0.09	0.15	0.15	0.25	0.30	0.40	0.45	0.50

* Biopower benefits are described in units of Fossil Fuel Energy Displaced because biomass has energy content associated with it.

FY2003 GPRA METRICS
WIND

GPRA 2003 Program Assumptions

Commercialization Dates
Commercialization: Commercially available

Capital Cost ($/kW) (constant 1999 dollars)

	2003	2004	2005	2006	2007	2010	2015	2020	2025	2030
Wind	945	930	910	895	875	830	810	785	770	755

O&M Cost ($/kW-yr)

	2003	2004	2005	2006	2007	2010	2015	2020	2025	2030
Wind	24.4	23.7	23.0	22.2	21.4	19.0	18.8	18.7	18.3	17.9

Technology Performance Indicators

	2003	2004	2005	2006	2007	2010	2015	2020	2025	2030
Capacity Factor (%)	40.0	41.2	42.3	43.2	44.2	47.1	46.0	46.3	44.9	43.6

Product Lifetime (years): 30

Other Assumptions: Technology data represents a weighted average of wind turbine characteristics for Class 4 (5.8 m/s average wind speeds) and Class 6 (6.7 m/s) sites, as defined by program planning documents for the Low Wind Speed Turbine project. Weighting changes from 20/80 for class 4/class 6 in 2003 to 75/25 in 2030. A One-year extension of the Production Tax Credit (PTC) was included in the analysis.

GPRA 2003 Analysis

Methodology:
The penetration estimate consists of two components:
1) Green Power Markets: The Green Power Market Model was used to project wind capacity installed to meet the demands of green markets. These estimates were then explicitly included in the NEMS runs. Projections for total green market potential are taken from NREL, *Growing the Green Power Market: Forecasting the Impacts of Customer Demand for Renewable Energy* (NREL/TP-620-30101).
2) NEMS: The National Energy Modeling System (NEMS) was run to estimate market penetration into the competitive bulk power marketplace. NEMS, as run by LBNL for the GPRA analysis, incorporates new technology cost and performance projections describing the expected development of a wind turbine tailored to low wind speed (Class 4) regimes. That turbine is targeted to have a levelized constant dollar cost of energy of 3 cents/kWh in 2010. A one-year extension of the Production Tax Credit is included in the wind analysis due to the expectation that the current credit will only be extended this long. As NEMS projections are not made for 2020-2030, a declining growth rate for the least-cost portion of the capacity projection, based on approximately half of the 2015-2020 rate, was used. Details on the NEMS modeling activity are provided elsewhere in this documentation.

Note: The results presented represent the amount of capacity projected to be installed in the years beginning 2003 (i.e., the benefit of program activities conducted during FY 2003).

GPRA 2003 Market Penetration Results (thousands of MW)

	2003	2004	2005	2006	2007	2010	2015	2020	2025	2030
Cumulative Penetration (above GPRA baseline)										
Without EERE	3.80 (GPRA baseline)									
With EERE	0.50	1.00	1.50	2.50	5.0	15.0	33.0	53.0	63.0	70.0
Annual Penetration										
Without EERE	0	0	0	0	0	0	0	0	0	0
With EERE	0.50	1.00	1.50	1.00	2.50	3.35	3.60	4.00	2.00	1.40

FY2003 GPRA METRICS
WIND

GPRA 2003 Benefits Summary

	2003	2004	2005	2006	2007	2010	2015	2020	2025	2030
Energy Metrics										
Total Primary Energy Displaced (Quads/yr.)	0.02	0.04	0.05	0.10	0.20	0.55	1.10	1.70	1.95	2.10
Direct Natural Gas Displaced (billion cu. ft./yr.)	11.5	24.0	33.5	56.5	95.0	285	650	1,045	1,215	1,310
Direct Petroleum Displaced (million barrels/yr.)	0.35	0.55	0.50	0.90	1.50	1.05	2.30	4.85	5.60	6.05
Direct Coal Displaced (million short tons/yr.)	0.20	0.50	1.00	2.05	4.70	13.0	20.5	29.0	33.5	36.0
Total* Displaced Barrels of Oil Equivalent (million barrels/yr.) (*sum of gas, oil, and coal)	2.90	6.15	9.20	16.5	32.5	89.5	175	270	310	335
Financial Metrics										
Energy Cost Savings (billions 1999$/yr.)	0.05	0.10	0.15	0.25	0.40	1.20	2.65	4.55	5.65	6.50
Non-Energy Cost Savings (billions 1999$/yr.)	0.01	0.01	0.01	0.02	0.04	0.10	0.30	0.50	0.55	0.60
Cumulative Consumer Investment (billions 1999$/yr.)	0.45	0.95	1.35	2.45	4.55	12.5	27.0	41.5	48.5	53.0
EERE Expenditures (millions 1999$/yr.)	40	40	40	Assume Level Funding				40	40	40
Other Govt. Expenditures (millions 1999$/yr.)	Negligible									
Private Sector Expenditures (millions 1999$/yr.)	$7 million cost-share in 2001									
Environmental Metrics										
Carbon Emissions Displaced (MMTCE/yr.)	0.30	0.70	1.10	2.05	4.10	11.5	22.0	33.0	38.0	41.0
SO_2 Displaced (Metric tons/yr.)	0.01	0.01	0.02	0.03	0.05	0.20	0.30	0.45	0.50	0.55
NO_x Displaced (Metric tons/yr.)	0.01	0.01	0.01	0.02	0.04	0.10	0.20	0.30	0.35	0.35

FY2003 GPRA METRICS
GEOTHERMAL

GPRA 2003 Program Assumptions

Commercialization Dates
Commercialization: Hydrothermal systems are commercially available. EGS systems are in the initial prototype stage.

Capital Cost ($/kW) (constant 1999 dollars)

	2003	2004	2005	2006	2007	2010	2015	2020	2025	2030
Geothermal	1,360	1,335	1,315	1,300	1,290	1,250	1,200	1,155	1,120	1,085

O&M Cost ($/kW-yr)

	2003	2004	2005	2006	2007	2010	2015	2020	2025	2030
Geothermal	78.9	76.4	74.0	72.3	70.6	65.6	61.3	57.6	56.0	54.3

Technology Performance Indicators

	2003	2004	2005	2006	2007	2010	2015	2020	2025	2030
Capacity Factor (%)	92.6	92.8	93.0	93.4	93.8	95.0	95.0	96.0	96.5	97.0

Product Lifetime (years): 30
Other Assumptions: Technology data from *Renewable Energy Technology Characterizations* (this report is currently being updated and the values may change). Data is weighted by the following factors: 90% Flashed Steam and 10% Binary. Enhanced geothermal systems (EGS) are not modeled in NEMS because that technology is in the early stages of development.

GPRA 2003 Analysis

Methodology:
The geothermal penetration estimate consists of three components:
1) Green Power Markets: The Green Power Market Model was used to project geothermal capacity installed to meet the demands of green markets. These estimates were then explicitly included in the NEMS runs. Projections for total green market potential are taken from NREL, *Growing the Green Power Market: Forecasting the Impacts of Customer Demand for Renewable Energy* (NREL/TP-620-30101).
2) NEMS: The National Energy Modeling System (NEMS) was run to estimate hydrothermal technology penetration into the competitive bulk power marketplace. NEMS, as run by LBNL for the GPRA analysis, incorporates technology cost and performance projections as taken from the *Renewable Energy Technology Characterizations*, published by DOE and EPRI in 1997. As NEMS projections are not made for 2020-2030, linear extrapolations for the least-cost portion of the capacity projection, based on the 2015-2020 increment, are used. Details on the NEMS modeling activity are provided elsewhere in this documentation.
3) Other Market Segments: The program prepared an estimate of EGS penetration in the post-2010 timeframe. This estimate was included in recognition of the assumed success of the newly initiated EGS R&D program. Approximately 500 MW per year are projected to come from EGS installations after 2010. The program is working to have EGS technology modeled directly by NEMS for next year's analysis.

Note: The results presented represent the amount of capacity projected to be installed in the years beginning 2003 (i.e., the benefit of program activities conducted during FY 2003).

GPRA 2003 Market Penetration Results (thousands of MW)

	2003	2004	2005	2006	2007	2010	2015	2020	2025	2030
Cumulative Penetration (above GPRA baseline)										
Without EERE	2.93 (GPRA baseline)									
With EERE	0.00	0.00	1.00	1.90	3.15	5.00	7.50	10.0	13.5	17.0
Annual Penetration										
Without EERE	0	0	0	0	0	0	0	0	0	0
With EERE	0.00	0.00	1.00	0.90	1.25	0.75	0.50	0.50	0.70	0.70

FY2003 GPRA METRICS
GEOTHERMAL

GPRA 2003 Benefits Summary

	2003	2004	2005	2006	2007	2010	2015	2020	2025	2030
Energy Metrics										
Total Primary Energy Displaced (Quads/yr.)	0.00	0.00	0.09	0.15	0.25	0.40	0.50	0.65	0.90	1.15
Direct Natural Gas Displaced (billion cu. ft./yr.)	0.00	0.00	50.5	84.0	120	190	305	410	560	705
Direct Petroleum Displaced (million barrels/yr.)	0.00	0.00	0.75	1.35	1.95	0.70	1.05	1.90	2.60	3.25
Direct Coal Displaced (million short tons/yr.)	0.00	0.00	1.55	3.00	6.05	8.60	9.70	11.5	15.5	19.5
Total* Displaced Barrels of Oil Equivalent (million barrels/yr.) (*sum of gas, oil, and coal)	0.00	0.00	14.0	25.0	41.5	59.5	82.0	105	145	180
Financial Metrics										
Energy Cost Savings (billions 1999$/yr.)	0.00	0.00	0.20	0.35	0.55	0.80	1.25	1.80	2.60	3.50
Non-Energy Cost Savings (billions 1999$/yr.)	0.00	0.00	-0.04	-0.07	-0.10	-0.15	-0.20	-0.20	-0.25	-0.25
Cumulative Consumer Investment (billions 1999$/yr.)	0.00	0.00	1.35	2.45	4.05	6.25	9.00	11.5	15.0	18.5
EERE Expenditures (millions 1999$/yr.)	27	27	27	Assume Level Funding				27	27	27
Other Govt. Expenditures (millions 1999$/yr.)	Negligible									
Private Sector Expenditures (millions 1999$/yr.)	$18 million cost-share in 2001									
Environmental Metrics										
Carbon Emissions Displaced (MMTCE/yr.)	0.00	0.00	1.65	3.00	5.25	7.70	10.5	13.0	17.5	22.0
SO_2 Displaced (Metric tons/yr.)	0.00	0.00	0.02	0.04	0.08	0.10	0.15	0.15	0.25	0.30
NO_x Displaced (Metric tons/yr.)	0.00	0.00	0.02	0.03	0.05	0.07	0.09	0.10	0.15	0.20

FY2003 GPRA METRICS
HYDROGEN

GPRA 2003 Program Assumptions

Commercialization Dates

Commercialization: Stationary Fuel cells are in early commercial use with full commercialization by 2010. Transport Fuels cells market consist of the Fuel Cell Sport Utility Vehicles (SUV) and the Fuel Cell Passenger Vehicles. Passenger size fuel cells and other Passenger Cars are expected to become commercially available by 2010.

Capital Cost (constant 1999 dollars)

	2003	2004	2005	2006	2007	2010	2015	2020	2025	2030
Fuel Cell Transport (1000 $/vehicle)	50	50	50	50	50	35.4	33.2	30.9	29.3	27.5
Stationary Power PEMFC ($/kW)	1,700	1,600	1,500	1,400	1,300	1,000	1,000	1,000	1,000	1,000

Fuel Cost ($/gallon – gasoline equivalent)

	2003	2004	2005	2006	2007	2010	2015	2020	2025	2030
Fuel Cell – Transport	2.95	2.70	2.45	2.35	2.25	1.95	1.70	1.45	1.45	1.45
Stationary Power-PEMFC	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Technology Performance Indicators

	2003	2004	2005	2006	2007	2010	2015	2020	2025	2030
Fuel Cell – fuel economy (mpg)	40+	40+	40+	40+	40+	40+	46+	50+	50+	50+
Fuel Cell – PEMFC electric efficiency (%)	68.0	69.0	70.0	71.0	72.0	75.0	75.0	75.0	75.0	75.0

Product Lifetime (years): 20-30 years

Other Assumptions: Technology data for Transport vehicles is the weighted average of data from the National Renewable Energy Laboratory for SUV's and passenger cars. Data for stationary power applications is from the ADL/OIT report, "Opportunities for Micropower and Fuel Cell Gas Turbine Hybrid Systems in Industrial Applications," DOE/ORO-2095, January 2000, and from program information for PEM fuel cells.

GPRA 2003 Analysis

Methodology:

The results presented represent the amount of vehicles and capacity projected to be sold and installed in the years beginning 2003 (i.e., the benefit of program activities conducted during FY 2003). These two markets were selected by the program as good surrogates for the overall benefits of hydrogen R&D. Other applications could have also been included. An off-line model is used to project fuel cell vehicles sales into the zero emission vehicle mandated and high-value markets. In addition to the fuel cell vehicles, the hydrogen program receives credit for a percentage of the CHP benefits due to the emergence of hydrogen fuel cells in CHP applications, based on projected budgets.

GPRA 2003 Market Penetration Results (thousands of vehicles or GW)

	2003	2004	2005	2006	2007	2010	2015	2020	2025	2030
Cumulative Penetration (thousands of vehicles above GPRA baseline or GW installed capacity)										
Fuel Cell - Transport	15	30	55	135	250	940	2,700	5,600	8,450	11,350
Stationary Power (GW)	0.00	0.00	0.00	0.00	0.00	0.00	3.45	6.85	10.0	13.5
Annual Penetration (thousands of vehicles or GW)										
Fuel Cell - Transport	15	15	20	80	115	230	350	580	580	580
Stationary Power (GW)	0.00	0.00	0.00	0.00	0.00	0.00	0.70	0.70	0.65	0.70

FY2003 GPRA METRICS
HYDROGEN

GPRA 2003 Benefits Summary

	2003	2004	2005	2006	2007	2010	2015	2020	2025	2030
Energy Metrics										
Total Primary Energy Displaced (Quads/yr.)	0.00	0.00	0.00	0.01	0.01	0.05	0.25	0.50	0.75	1.00
Direct Natural Gas Displaced (billion cu. ft./yr.)	0.00	0.00	0.00	0.00	0.00	0.00	55.5	110	165	230
Direct Petroleum Displaced (million barrels/yr.)	0.10	0.20	0.35	0.90	1.85	6.75	22.0	48.5	75.0	100
Direct Coal Displaced (million short tons/yr.)	0.00	0.00	0.00	0.00	0.00	0.00	1.75	3.05	4.60	6.30
Total* Displaced Barrels of Oil Equivalent (million barrels/yr.) (*sum of gas, oil, and coal)	0.10	0.20	0.35	0.90	1.85	6.75	36.5	76.5	115	160
Financial Metrics										
Energy Cost Savings (billions 1999$/yr.)	0.00	0.00	0.00	-0.05	-0.10	0.20	1.55	3.85	6.10	8.40
Non-Energy Cost Savings (billions 1999$/yr.)	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.03	0.05	0.09
Cumulative Consumer Investment (billions 1999$/yr.)	0.80	1.60	2.65	6.65	13.0	33.5	92.0	180	255	320
EERE Expenditures (millions 1999$/yr.)	27	27	27	Assume Level Funding				27	27	27
Other Govt. Expenditures (millions 1999$/yr.)	Negligible									
Private Sector Expenditures (millions 1999$/yr.)	$8 million cost-share in 2001 (per SMS)									
Environmental Metrics										
Carbon Emissions Displaced (MMTCE/yr.)	0.05	0.05	0.10	0.25	0.55	2.00	8.65	18.0	27.5	37.5
SO_2 Displaced (Metric tons/yr.)	0.00	0.00	0.00	0.00	0.00	0.00	0.06	0.10	0.15	0.20
NO_x Displaced (Metric tons/yr.)	0.00	0.00	0.00	0.01	0.01	0.03	0.10	0.20	0.30	0.45

FY2003 GPRA METRICS
DISTRIBUTED ENERGY RESOURCES PROGRAM

GPRA 2003 Program Assumptions

Commercialization Dates
Commercialization: The CHP systems modeled are commercially available, for both commercial and industrial applications.

Capital Cost ($/kW) (constant 1999 dollars)

	2003	2004	2005	2006	2007	2010	2015	2020	2025	2030
CHP - Industrial	930	920	910	900	890	855	800	750	690	640
CHP - Commercial	1,565	1,550	1,540	1,505	1,470	1,370	1,265	1,155	1,045	935

O&M Cost ($/kW-yr)

	2003	2004	2005	2006	2007	2010	2015	2020	2025	2030
CHP - Industrial	38.0	37.5	37.0	36.5	36.0	34.5	33.0	31.0	29.5	27.5
CHP - Commercial	75.5	75.0	74.5	73.5	72.5	69.0	65.5	62.0	58.5	55.0

Technology Performance Indicators

	2003	2004	2005	2006	2007	2010	2015	2020	2025	2030
CHP- Industrial heat rate (btu/kWh)	4729	4726	4722	4719	4716	4706	4690	4674	4665	4660
CHP- Commercial heat rate (btu/kWh)	5696	5668	5640	5612	5584	5503	5373	5249	5245	5240

Product Lifetime (years): 30
Other Assumptions: Technology data from Nexus Energy Group. The Industrial technology characterizations assume a 10 MW gas turbine. The commercial technology assumes a 1 MW gas turbine for commercial applications. Other technology configurations could also have been used, but gas turbines were selected due to their relative maturity and commercial attractiveness.

GPRA 2003 Analysis

Methodology:
The distributed energy resources program includes many R&D activities in diverse technology areas. Because not all of these could be modeled, the methodology assumed that the benefits of increased combined heat and power (CHP), being a major portion of the total program benefits, would be a good surrogate for total benefits. The National Energy Modeling System (NEMS) was run to estimate market penetration into the commercial and industrial sectors. As NEMS projections are not made for 2020-2030, linear extrapolations, based on the 2015-2020 increment, are used for those out-years. Program DATA FOR CHP technology cost and performance was used for modeling purposes. The NEMS runs also incorporate a number of other fixes to the model, made to allow NEMS to better reflect the potential for renewables. Details on the NEMS modeling activity are provided elsewhere in this documentation.
Note: The results presented represent the amount of capacity projected to be installed in the years beginning 2003 (i.e., the benefit of program activities conducted during FY 2003).

GPRA 2003 Market Penetration Results (thousands of MW)

	2003	2004	2005	2006	2007	2010	2015	2020	2025	2030
Cumulative Penetration (above GPRA baseline)										
Without EERE	4.3 (GPRA baseline)									
With EERE	2.30	3.90	5.45	6.95	8.30	12.25	15.5	20.5	25.0	29.0
Annual Penetration										
Without EERE	0	0	0	0	0	0	0	0	0	0
With EERE	2.30	1.60	1.55	1.50	1.35	1.30	0.50	1.00	0.90	0.80

FY2003 GPRA METRICS
DISTRIBUTED ENERGY RESOURCES PROGRAM

GPRA 2003 Benefits Summary

	2003	2004	2005	2006	2007	2010	2015	2020	2025	2030
Energy Metrics										
Total Primary Energy Displaced (Quads/yr.)	0.10	0.20	0.30	0.35	0.40	0.40	0.45	0.55	0.65	0.80
Direct Natural Gas Displaced (billion cu. ft./yr.)	76.0	125	160	180	190	195	255	330	410	485
Direct Petroleum Displaced (million barrels/yr.)	2.15	2.95	2.35	2.90	3.00	0.70	0.90	1.55	1.90	2.25
Direct Coal Displaced (million short tons/yr.)	1.40	2.75	4.90	6.55	9.40	8.65	8.05	9.10	11.5	13.5
Total* Displaced Barrels of Oil Equivalent (million barrels/yr.) (*sum of gas, oil, and coal)	19.0	32.0	44.5	53.5	64.0	60.0	68.0	85.0	105	125
Financial Metrics										
Energy Cost Savings (billions 1999$/yr.)	0.60	0.95	1.25	1.55	1.75	2.05	2.60	3.50	4.20	4.85
Non-Energy Cost Savings (billions 1999$/yr.)	-0.01	-0.01	-0.02	-0.03	-0.05	-0.04	-0.02	-0.07	0.10	0.20
Cumulative Consumer Investment (billions 1999$/yr.)	2.25	3.70	5.05	6.40	7.55	10.5	13.0	15.5	17.5	19.0
EERE Expenditures (millions 1999$/yr.)	62	62	62	Assume Level Funding				62	62	62
Other Govt. Expenditures (millions 1999$/yr.)	Negligible									
Private Sector Expenditures (millions 1999$/yr.)	$25 million cost-share in 2001 (per SMS)									
Environmental Metrics										
Carbon Emissions Displaced (MMTCE/yr.)	2.05	3.75	5.65	7.25	9.25	10.5	11.5	14.0	17.0	20.0
SO_2 Displaced (Metric tons/yr.)	0.02	0.05	0.09	0.15	0.20	0.25	0.30	0.35	0.40	0.45
NO_x Displaced (Metric tons/yr.)	0.02	0.03	0.05	0.07	0.09	0.10	0.10	0.15	0.15	0.20

FY2003 GPRA METRICS
HIGH TEMPERATURE SUPERCONDUCTORS

GPRA 2003 Program Assumptions

Commercialization Dates
Refined Prototype: The commercialization process for HTS systems is currently in the refined prototype stage, expecting to reach full commercialization status by the end of the analysis period.

Capital Cost (constant 1999 dollars)

	2003	2004	2005	2006	2007	2010	2015	2020	2025	2030
HTS Motors ($/kW)	243									
HTS Transformers ($/kW)	760									
HTS Generators ($/kW)	307									
HTS Cable ($/miles)	440									

Technology Performance Indicators - Energy Loss Savings (%)

	2003	2004	2005	2006	2007	2010	2015	2020	2025	2030
HTS Motors	1.35%									
HTS Transformers	1.20%									
HTS Generators	1.50%									
HTS Cable (miles)	1.30%									

Product Lifetime (years): 30
Other Assumptions: Technology data from model estimates by the program for cost characteristics and energy-loss savings.

GPRA 2003 Analysis

Methodology:
Note: The results presented represent the number of units projected to be installed in the years beginning 2003 (i.e., the benefit of program activities conducted during FY 2003). These results are taken from the FY2001 HTS model created by Joe Mulholland.

GPRA 2003 Market Penetration Results (thousands of MW)

	2003	2004	2005	2006	2007	2010	2015	2020	2025	2030
Cumulative Penetration (above GPRA baseline)										
HTS Motors	40	85	210	795	1,400	3,130	12,400	27,600	42,800	58,000
HTS Transformers	3	6	15	40	65	130	500	1,150	1,850	2,550
HTS Generators	-	-	-	7	14	35	120	290	460	630
HTS Cable (miles)	6	12	30	115	200	450	1,850	5,450	9,050	12,650
Annual Penetration										
HTS Motors	40	45	125	585	605	575	1,850	3,040	3,040	3,440
HTS Transformers	3	3	9	25	25	25	74	130	140	140
HTS Generators	-	-	-	7	7	7	17	34	34	34
HTS Cable (miles)	6	6	18	85	85	85	280	720	720	720

FY2003 GPRA METRICS
HIGH TEMPERATURE SUPERCONDUCTOR

GPRA 2003 Benefits Summary

	2003	2004	2005	2006	2007	2010	2015	2020	2025	2030
Energy Metrics										
Total Primary Energy Displaced (Quads/yr.)	0.00	0.00	0.01	0.05	0.05	0.10	0.30	0.35	0.40	0.45
Direct Natural Gas Displaced (billion cu. ft./yr.)	0.75	1.50	3.45	14.0	21.5	49.0	175	210	250	285
Direct Petroleum Displaced (million barrels/yr.)	0.02	0.04	0.05	0.20	0.35	0.20	0.60	0.95	1.15	1.30
Direct Coal Displaced (million short tons/yr.)	0.01	0.03	0.10	0.50	1.10	2.20	5.50	5.80	6.85	7.90
Total* Displaced Barrels of Oil Equivalent (million barrels/yr.) (*sum of gas, oil, and coal)	0.20	0.40	0.95	4.15	7.40	15.5	46.5	54.0	63.5	73.5
Financial Metrics										
Energy Cost Savings (billions 1999$/yr.)	0.00	0.00	0.00	0.05	0.10	0.20	0.70	0.90	1.15	1.45
Non-Energy Cost Savings (billions 1999$/yr.)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Cumulative Consumer Investment (millions 1999$/yr.)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
EERE Expenditures (millions 1999$/yr.)	37	37	37	Assume Level Funding				37	37	37
Other Govt. Expenditures (millions 1999$/yr.)	Negligible (royalty payments not included)									
Private Sector Expenditures (millions 1999$/yr.)	$19 million cost-share in 2001 (per SMS)									
Environmental Metrics										
Carbon Emissions Displaced (MMTCE/yr.)	0.00	0.05	0.10	0.50	0.95	1.95	5.80	6.60	7.80	8.95
SO_2 Displaced (Metric tons/yr.)	0.00	0.00	0.00	0.01	0.02	0.03	0.09	0.09	0.10	0.10
NO_x Displaced (Metric tons/yr.)	0.00	0.00	0.00	0.01	0.01	0.02	0.05	0.06	0.07	0.08

SECTION II –

Detailed Results

Overview of FY 2003 Benefits Analysis

The Office of Power Technologies (OPT) manages research in two broad areas: 1) Energy Supply Technologies; and 2) Electricity Delivery. Several different approaches are required to estimate the benefits of this wide array of programs. The analytical approaches used for FY 2003 are documented in this report, as are the results of these analyses. This chapter provides a broad overview of the approaches taken for each of the two OPT research areas. Greater detail for each OPT program is provided later in this report in program-specific discussions.

Energy Supply Technology Programs

OPT manages seven renewable energy technology programs – photovoltaics (PV), biopower, wind, geothermal, concentrating solar power (CSP), solar buildings and hydropower. The five electricity generating technologies (not including hydropower which is not part of this analysis) were analyzed within the segmentation framework shown in Figure 1. Solar Buildings program benefits, although shown in Figure 1, were analyzed using a different approach because solar building technologies produce thermal energy and not electricity. This different approach is described later in this report in the Solar Buildings chapter. The benefits of the DOE Distributed Energy Resources program are also estimated as part of the framework shown in Figure 1.

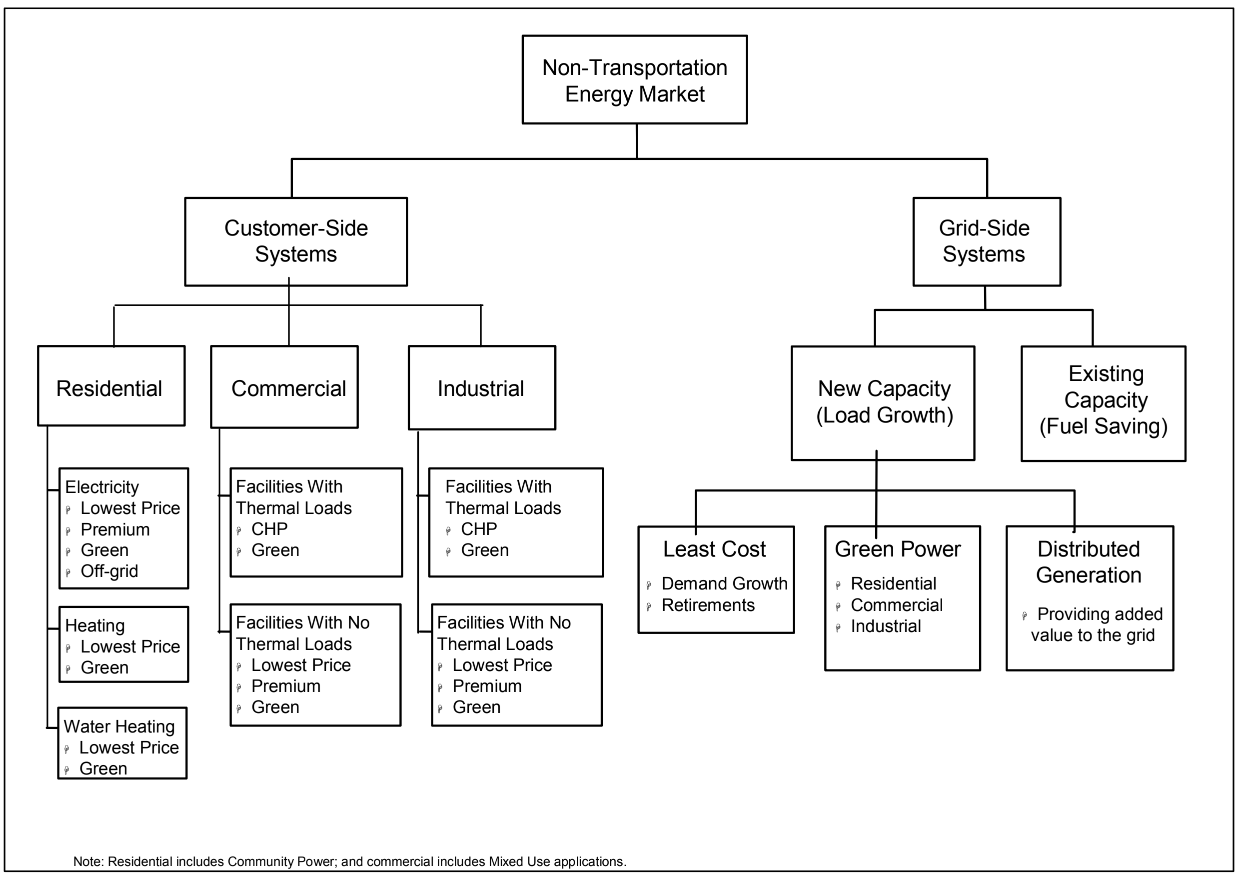

Figure 1 – Market Segmentation for OPT Benefits Analysis

The U.S. non-transportation energy market was segmented into: 1) Grid-Side Systems -- systems that are on the grid side of the meter, and owned by utilities or other power suppliers; and 2) Customer-Side

Systems -- systems installed at customer locations on the customer side of the meter. Figure 2 shows how the various market segments were analyzed to calculate OPT program benefits.

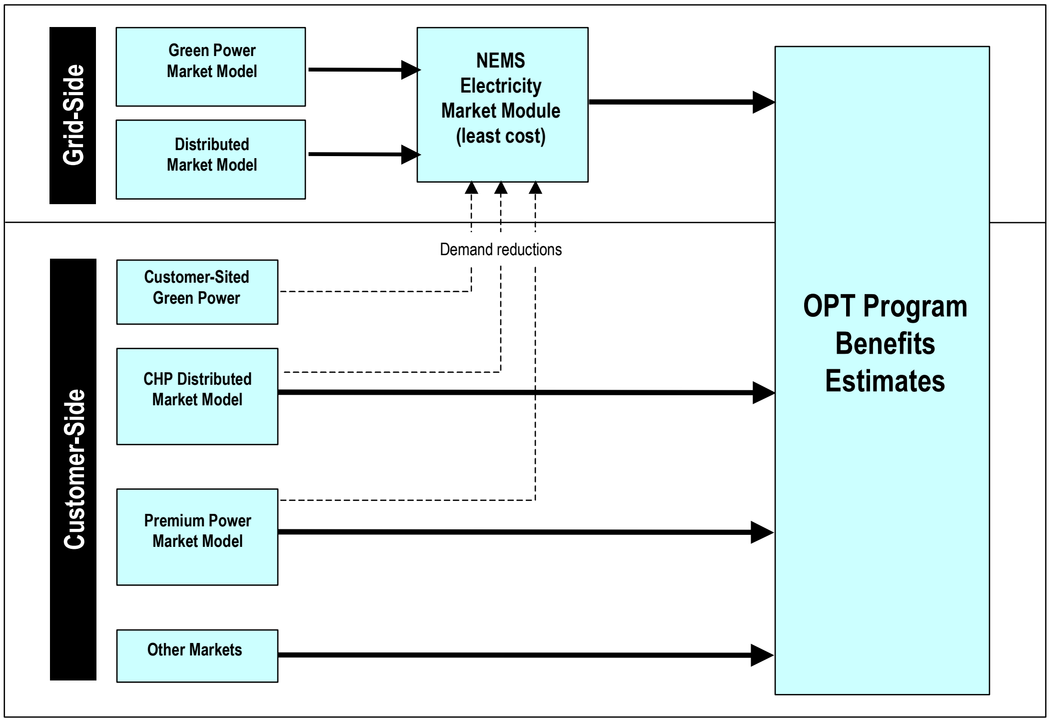

Figure 2 - Analysis Framework for Estimating OPT Benefits

Grid-Side Market Segment

Figure 3 shows a detailed breakout of the Grid-Side Market segment. The five OPT electricity generating technologies fall into three primary market segments as follows:

Least-Cost Power

The least cost segment refers to the bulk power market, which has traditionally been the province of the regulated utility industry. In analyzing this segment, growing demand and the need to replace retiring plants is met by projecting the installation of a mixture of power plants. The mixture chosen to meet this growing demand may have many attributes, but the primary one is that the lowest-cost option is typically selected through a detailed analysis process that compares all available options, both renewable and conventional.

Although this segment of the market may in the future be implemented through competitive bidding into a power pool or through bilateral contracts between suppliers and consumers, it will still be likely that the lowest cost option will capture the largest portion of the market. This segment of the market also includes renewables that could be installed to supply electricity at a cost lower than the variable operating cost of existing capacity (commonly referred to as the fuel-saving mode).

For OPT analyses, the National Energy Modeling System (NEMS) is used to estimate future generating technology use in this market segment. This is the same analysis approach as that used by EIA for the Annual Energy Outlook. Lawrence Berkeley National Laboratory (LBNL) runs NEMS for OPT. Significant changes to EIA's technology assumptions and EIA's approaches to characterizing renewables' ability to compete in the competitive market have been made by LBL. These changes are believed to characterize OPT technologies more accurately. An important change, which is common to all five generating technologies, is LBL's use of technology data from the EPRI/DOE *Renewable Energy*

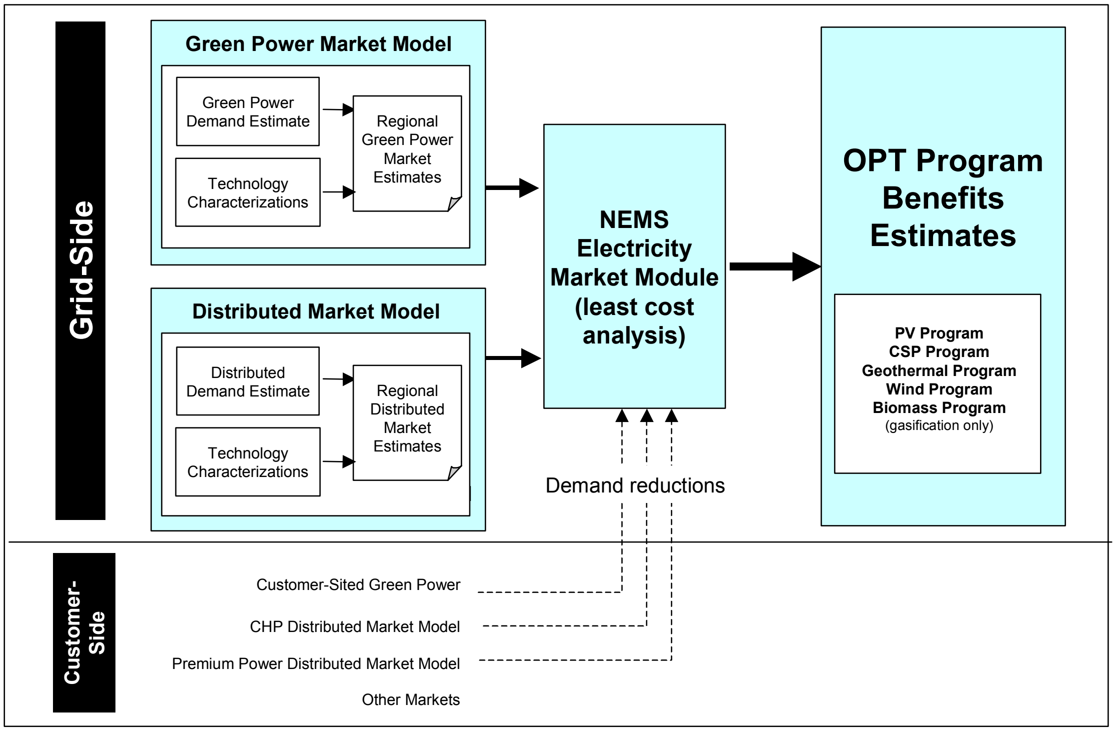

Figure 3 - Analysis Detail for Grid-Side Market Benefits Estimates

Technology Characterizations. A variety of technology-specific changes have also been made. These changes had the greatest impact on the wind and geothermal technology projections, resulting in increased penetration of each when compared to the AEO projections. The technology-specific changes made are described in this report in the appropriate program discussion in later chapters.

Green Power

OPT sponsored the development of a Green Power Market Model by Princeton Energy Resources International (PERI). In this model, the projected green power market size is allocated to the various OPT technologies using an algorithm similar to that which is used by NEMS. The allocation is performed using a logit function approach to calculating market sharing. The logit function uses the various competing technologies' levelized cost of energy to determine which will be chosen by green power suppliers in a particular region to meet the demand for green power in that region.

The size and timing of the overall green market are key assumptions made for this analysis. Several changes from last year's assumptions have been included this year. The changes that have been incorporated for this year's analysis are a more detailed and regionalized set of assumptions for electricity market restructuring from the *Growing the Green Power Market: Forecasting the Impacts of Customer Demand for Renewable Energy*, a recent report by Blair Swezey et al. completed for the National Renewable Energy Laboratory (NREL). (4) These assumptions include the dates for initiation of market restructuring as well as the assumed green power penetration rates, a change in the time periods tracked in the analysis, and a new method for calculating funds from program participants.

A detailed discussion of this analysis and its results can be found in Appendix B. The results of the Green Power Market Model runs were explicitly included in the NEMS runs by specifying the green capacity as planned capacity. The effect of this exogenous determination is to reduce future levels of new demand such that when NEMS is run the projections of new conventional capacity and new least-cost renewables are lower than in the base case where no green capacity is explicitly included.

Distributed Generation

Grid-Side Distributed Generation Market benefits are realized when technologies are strategically installed in locations where they can provide benefits to the distribution system beyond the basic commodity supply benefits. An example of such a benefit is the ability to defer, or potentially avoid, a distribution system upgrade. This Distributed Generation Market has yet to materialize for renewables, although a number of OPT programs are working to facilitate renewable penetration into this subsegment.

Customer-Side Market Segment

Figure 4 shows a detailed breakout of the Customer-Side Market segment.

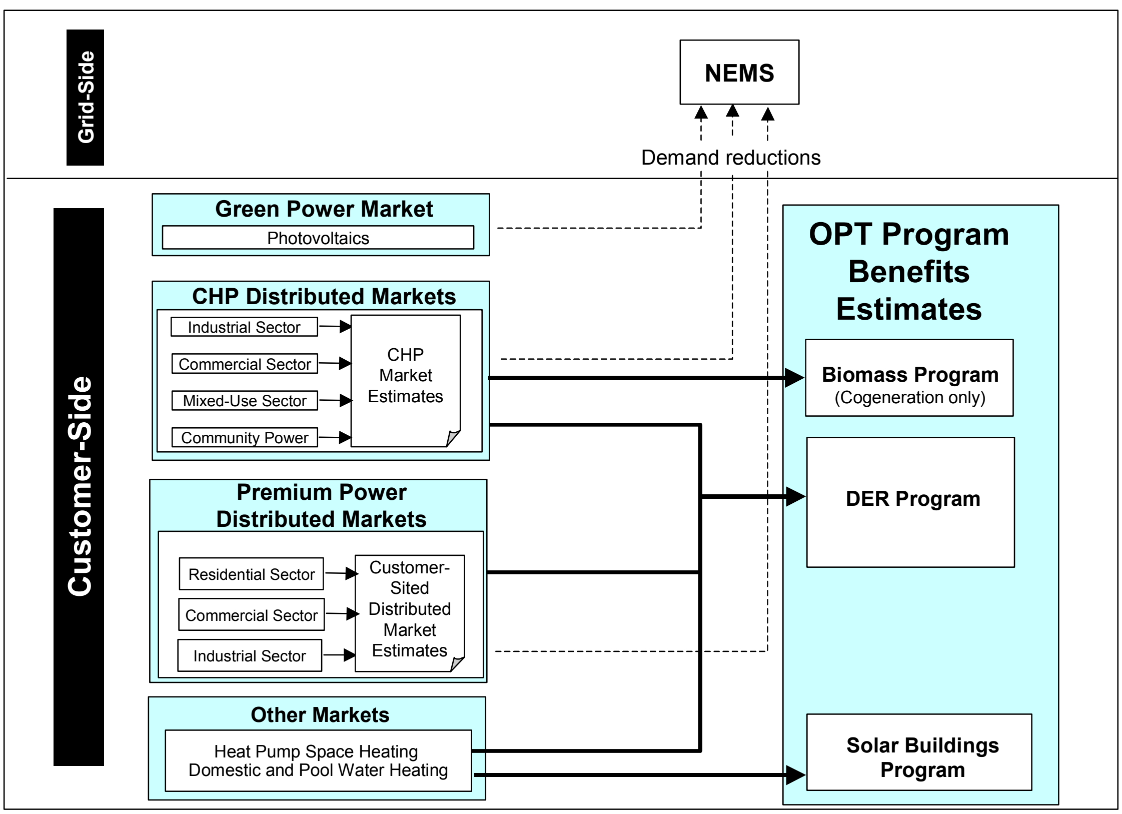

Figure 4 - Analysis Detail for Customer-Side Benefits Estimates

Green Power

Photovoltaics (PV) was the sole option examined for residential and commercial customer-side green power installations. Although other renewable technologies may well be installed in the residential and commercial sub-segments in the future, PV appears to be at the moment the only technology with significant early market momentum, largely due to the Million Solar Roofs (MSR) program. There may also be small numbers of customer-sited PV systems that are not actually owned by the customer. The extent of PV penetration into the customer-sited market segment was projected to be very closely tied to the 2010 goal of the MSR program.

Overall, although customer-sited PV systems represented the vast majority of projected PV installations for the FY 2003 benefits analysis, customer-sited renewables accounted for only a small portion of all projected renewable penetration.

Combined Heat and Power

The Customer-Side Market segment also includes combined heat and power (CHP, or cogeneration) applications. In these applications, commercial and industrial facilities are equipped to produce both power and thermal energy. The OPT Distributed Energy Resources (DER) program's benefits are estimated from this market segment. Also estimated as part of the CHP market was industrial biomass CHP, which is reported as part of the DER benefits, and not in OPT's biopower benefits totals. Five OPT programs are considered to contribute to increased future CHP use. These programs include: Distributed Technologies, Power Systems Reliability, Distributed Power, Energy Storage, and Hydrogen. While the first four effectively comprise what is reported as the DER program's benefits, the Hydrogen program is reported separately. Hydrogen technologies are expected to start impacting cogeneration and other DER efforts after 2010, and therefore do not start receiving credit for DER technology introduction until 2015.

Biomass cogeneration in the industrial market subsegment was the other customer-sited renewable technology analyzed. The analysis of biopower technologies was broken into three categories: direct-fired, gasification-based generation and cogeneration. (See Appendix H for a more-detailed representation of biopower technologies.) Although, direct-fired and gasification both increase significantly in the out years of the analysis, the largest impact made by biomass resources is in co-firing or cogeneration applications. This market opportunity for biopower increased rapidly in the 1980s with the enactment of PURPA. Only modest future expansion is projected by the Energy Information Administration (EIA) using NEMS.

Premium Power Distributed

On the Customer-Side, there are opportunities for providing power in applications where the customer is willing to pay a premium for higher quality power, for power with higher reliability, or for power with greater certainty of future price stability. There is no projected penetration of OPT power technologies into this market segment for GPRA reporting.
More-conventional technologies, using natural gas, were deemed more likely to be used for premium power applications for the foreseeable future. Although not modeled, it should be noted that some "conventional" DER technologies could also meet the needs of this market.

Other Markets

Other Markets in the Customer-Side Market include markets for solar domestic hot water (SDHW) and solar pool heating (SPH) technologies. These two technologies comprise the Solar Buildings program and represent almost the entire end use for solar thermal collectors. Benefits are derived from the natural gas and electricity displaced that conventionally fuels these heating requirements.

Electricity Delivery Programs

The benefits of the OPT electricity delivery programs cannot be estimated within the framework described above, and must be estimated using various techniques developed by OPT program personnel or their contractors. Table 1 summarizes these programs and the approaches used for the analyses. Greater detail for each program is provided in the program-specific chapters later in this report.

Table 1. Approaches Used For Benefits Estimates of OPT Electricity Delivery Programs

Program Element	Benefits Estimation Approach
Renewable Energy Production Incentive (REPI)	The amount of capacity expected to be installed during the remaining two years of this program was estimated to be the same as what has been installed in the first eight years of the program.
Solar Program Support (Competitive Solicitation)	Program developed an estimate of the renewable capacity that is expected to result from the solicitation.
Hydrogen	A market penetration model was developed to estimate the penetration of fuel cell-powered passenger cars and SUVs into both high-value and ZEV mandate markets. The Hydrogen program claims a portion of the benefits of the DER program from 2015 to 2030 as hydrogen technologies are expected to penetrate in this market segment. The program has eliminated the estimate of penetration from mini-grid fuel cells into residential markets.
Distributed Technologies, Power Systems Reliability, Distributed Power and Energy Storage	The benefits of these three programs are assumed to be included in the Distributed Energy Resource program benefits.
High Temperature Superconductivity	Market penetration estimates were developed for more-efficient high temperature superconducting motors, generators, transformers, and cables.

A summary of the estimated benefits from the Energy Supply Technology Programs is presented in Table 1. The table shows capacity projections which are cumulative, but which begin with a baseline as of the end of 2002. In other words, they do not include the installed capacity base as of the end of 2002. These capacity projections form the basis for the estimation of the various GPRA metrics for the five generating technology programs.

Annual electricity production for each technology was estimated from these capacity projections, and from appropriate capacity factors for each technology. From the annual energy production, primary energy displacement, energy cost savings, carbon displacement, NOx displacement, and SOx displacement were also calculated. The *GPRA Data Call: Fiscal Year 2003* guidance document (Appendix D) was used as the source for information on fuel mix displaced, emissions factors, average grid heat rates, fuel prices, etc.

Table 2 provides comparable results for the OPT Electricity Delivery Programs. The estimation of the benefits of each technology program required a unique analytical approach. The individual chapters for each of these programs later in this report describe the various approaches used. Table 2 provides information on primary energy displacement, energy cost savings, and non-energy cost savings (if applicable) associated with each of the electricity delivery programs.

Table 1. Summary of Benefits Estimates for Energy Supply Technology Programs

	2007	2010	2015	2020	2025	2030
Cumulative Capacity Installed Since 2002 (thousands of MW)						
Photovoltaics	0.50	1.25	3.45	5.80	8.10	10.5
Concentrating Solar Power	0.07	0.25	0.80	2.05	3.20	4.30
Total Solar Program	0.55	1.50	4.25	7.85	11.5	14.5
Biopower	4.15	7.00	8.75	10.5	12.5	14.0
Wind	5.0	15.0	33.0	53.0	63.0	70.0
Geothermal	3.15	5.00	7.50	10.0	13.5	17.0
Annual Energy Production (billions of kilowatthours/year)						
Photovoltaics	0.85	2.30	6.25	10.5	14.5	19.0
Concentrating Solar Power	0.30	1.40	4.85	14.0	21.5	29.0
Total Solar Program	1.20	3.70	11.0	24.0	36.0	48.0
Biopower*	2.45	5.95	10.5	12.0	15.0	18.0
Wind	20.0	62.5	135	215	250	270
Geothermal	25.5	41.5	62.5	84.0	115	145
Annual Primary Energy Displacement (quadrillion Btu/year)						
Solar Buildings	0.03	0.05	0.09	0.15	0.25	0.35
Photovoltaics	0.01	0.02	0.05	0.10	0.10	0.15
Concentrating Solar Power	0.003	0.01	0.04	0.10	0.15	0.25
Total Solar Program	0.04	0.08	0.20	0.35	0.50	0.70
Biopower**	0.35	0.55	0.70	0.80	0.95	1.05
Wind	0.20	0.55	1.10	1.70	1.95	2.10
Geothermal	0.25	0.40	0.50	0.65	0.90	1.15

* Biomass Direct Electricity Displaced does not include generation from co-firing capacity, as this is not new capacity, but rather is considered to be a fuel switch for existing or planned capacity, which is addressed as energy displacement.

** Biopower benefits are cited in terms of Fossil Fuel Energy Displaced because biomass is, itself, a primary energy source.

Table 1. Summary of Benefits Analyses for Energy Supply Technology Programs (cont.)

	2007	2010	2015	2020	2025	2030
Annual Energy Cost Savings (billions of dollars/year)						
Solar Buildings	0.15	0.30	0.55	1.00	1.65	2.45
Photovoltaics	0.02	0.05	0.10	0.20	0.35	0.45
Concentrating Solar Power	0.01	0.03	0.10	0.30	0.50	0.70
Total Solar Program	0.20	0.35	0.80	1.50	2.45	3.60
Biopower	-0.40	-0.70	-0.85	-1.00	-1.15	-1.30
Wind	0.40	1.20	2.65	4.55	5.65	6.50
Geothermal	0.55	0.80	1.25	1.80	2.60	3.50
Annual Non-Energy Cost Savings (billions of dollars/year)						
Photovoltaics	0.01	0.02	0.05	0.09	0.10	0.15
Concentrating Solar Power	0.00	0.00	-0.01	-0.02	-0.04	-0.05
Total Solar Program	0.01	0.02	0.05	0.07	0.09	0.10
Biopower	0.09	0.15	0.15	0.15	0.20	0.20
Wind	0.04	0.10	0.30	0.50	0.55	0.60
Geothermal	-0.10	-0.15	-0.20	-0.20	-0.25	-0.25
Annual Carbon Displacement (million metric tons of carbon equivalent/year)						
Solar Buildings	0.40	0.65	1.25	2.20	3.60	5.35
Photovoltaics	0.20	0.40	1.05	1.60	2.25	2.90
Concentrating Solar Power	0.05	0.25	0.80	2.10	3.30	4.45
Total Solar Program	0.60	1.35	3.10	5.90	9.15	12.5
Biopower	8.60	14.0	17.0	20.5	23.5	27.0
Wind	4.10	11.5	22.0	33.0	38.0	41.0
Geothermal	5.25	7.70	10.5	13.0	17.5	22.0

Table 1. Summary of Benefits Analyses for Energy Supply Technology Programs (cont.)

	2007	2010	2015	2020	2025	2030
Annual SO_x Displacement (millions of metric tons/year)						
Solar Buildings	0.01	0.02	0.03	0.04	0.06	0.09
Photovoltaics	0.003	0.01	0.02	0.02	0.03	0.05
Concentrating Solar Power	0.001	0.004	0.01	0.03	0.05	0.06
Total Solar Program	0.01	0.03	0.05	0.09	0.15	0.20
Biopower	0.15	0.25	0.30	0.35	0.45	0.50
Wind	0.05	0.20	0.30	0.45	0.50	0.55
Geothermal	0.08	0.10	0.15	0.15	0.25	0.30
Annual NO_x Displacement (millions of metric tons/year)						
Solar Buildings	0.01	0.01	0.02	0.03	0.04	0.06
Photovoltaics	0.002	0.01	0.01	0.02	0.02	0.03
Concentrating Solar Power	0.001	0.003	0.01	0.02	0.03	0.04
Total Solar Program	0.01	0.02	0.03	0.06	0.09	0.10
Biopower	0.15	0.25	0.30	0.40	0.45	0.50
Wind	0.04	0.10	0.20	0.30	0.35	0.35
Geothermal	0.05	0.07	0.09	0.10	0.15	0.20

Table 2. Summary of Benefits Analyses for Electricity Delivery Programs

	2007	2010	2015	2020	2025	2030
Annual Primary Energy Displacement (quadrillion Btu/year)						
Distributed Energy Resources	0.40	0.40	0.45	0.55	0.65	0.80
Hydrogen	0.00	0.05	0.25	0.50	0.75	1.00
High Temperature Superconductivity	0.05	0.10	0.30	0.35	0.40	0.45
Renewable Energy Production Incentive	0.04	0.03	0.03	0.03	0.03	0.03
Solar Program Support (Competitive Solicitation)	0.01	0.01	0.01	0.01	0.01	0.01
Annual Energy Cost Savings (billions of dollars/year)						
Distributed Energy Resources	1.75	2.05	2.60	3.50	4.20	4.85
Hydrogen	0.00	0.20	1.55	3.85	6.10	8.40
High Temperature Superconductivity	0.10	0.20	0.70	0.90	1.15	1.45
Renewable Energy Production Incentive	0.07	0.07	0.07	0.07	0.08	0.09
Solar Program Support (Competitive Solicitation)	0.01	0.01	0.01	0.01	0.01	0.01
Annual Carbon Displaced (million metric tons of carbon equivalent/year)						
Distributed Energy Resources	9.25	10.5	11.5	14.0	17.0	20.0
Hydrogen	0.55	2.00	8.65	18.0	27.5	37.5
High Temperature Superconductivity	0.95	1.95	5.80	6.60	7.80	8.95
Renewable Energy Production Incentive[1]	15.0	13.5	12.0	11.5	11.5	11.5
Solar Program Support (Competitive Solicitation)	0.05	0.05	0.05	0.05	0.05	0.05

1) A factor of x22 was used for calculation of carbon displacement for REPI due to the dominance (428 MW of 436 MW total) of landfill gas plants that qualify for this incentive. Landfill gas plants burn methane that would otherwise be released to the atmosphere. Methane lasts significantly longer in the atmosphere than carbon dioxide and other green house gases, and therefore has a greater impact on climate change.

FY2003 GPRA METRICS
SOLAR PROGRAM
SUB-PROGRAM: SOLAR BUILDINGS

	2007	2010	2015	2020	2025	2030
Market Penetration Estimate (Numbers of systems since 2002 in thousands)						
DHW	65	125	360	835	1,950	3,500
Pool Heating	150	255	475	690	1,130	1,455
Total	215	380	835	1,525	3,080	4,955
Annual Benefits						
Energy Displaced (quads)	0.03	0.05	0.09	0.15	0.25	0.35
Energy Cost Savings ($ billion)	0.15	0.30	0.55	1.00	1.65	2.45
Carbon Displaced (MMCTE)	0.40	0.65	1.25	2.20	3.60	5.35

Table 1. Summary of Solar Buildings Analysis

Market Segments

The solar buildings program includes technologies for solar domestic hot water (SDHW) and solar pool heating (SPH) in residential and commercial buildings. According to EIA data[1], SPH is the largest end use for solar thermal collectors, representing 95% of the total square feet shipped in 1999. SDHW accounted for nearly all the rest of the market, with only 0.5% for other uses such as space heating. The residential market accounts for more than 90% of each of these end uses. No significant differences were found between the FY 2003 and FY 2002 analyses, so many of the projections have remained constant. As discussed below, the SDHW is assumed to compete with electric water heating, and the SPH competes with natural gas.

System Definition and Economics

<u>Solar Domestic Hot Water</u>

Typical residential SDHW systems have collector area ranging from 40 to 80 square feet, depending on geographic location, and costs ranging from $2,250 to $3,300.[2] Other studies show similar costs for conventional solar systems, although thermosiphon or integral collector systems are available for about half that cost in package units with perhaps 20 square feet or less of collector area. Currently the SWAP program in Florida is installing a 20 square foot integratal collector system in low-income homes for $1500 to $1700[3]. Note that 80% of solar collector sales (by square feet) went to five states: Florida (44%), California (25%), Arizona (5%), Hawaii (3%), and Nevada (3%).[4] Because most installations are in warmer climates, for this GPRA analysis it is reasonable to assume a cost of $2500 for an average SDHW system using 40 square feet of conventional collector technology.

The analysis assumes the introduction of a low-cost polyethylene collector in 2010. Existing flat-plate collectors cost about $10 per square foot[5], or about $25 per square foot after manufacturer profit and markups by the distributor and dealer/contractor[6]. Assuming that the new collector could be sold for $15 per square foot, the system cost would decrease by $400, to $2100. An integral collector design could reduce the cost further, perhaps below $2000 for a system of comparable capacity.

For this GPRA analysis, the energy saved by the SDHW system is assumed to be 2,752 kWh per year. Because the warmer areas of the country have lower hot water use per capita and warmer supply water temperature, the actual water-heating load across the country is not uniform. This number corresponds to the national-average site electricity savings calculated by ADL, averaging the cases of high and medium water draw[7]. The ADL analysis was based on simulation model runs for five cities corresponding to the five DOE climate zones, although their method for determining the national average was not disclosed.

The solar fraction of an SDHW system is the percentage of water heating energy supplied by solar energy. For a typical SDHW system, the solar fraction is 60%, with the remaining 40% supplied by an auxiliary system, usually an electric heater. System cost decreases if the solar fraction drops below 50% and increases greatly if it is pushed to 80% or higher. The energy savings of 2,752 kWh corresponds to the 60% solar energy supplied by an SDHW system in a household with an average water heating load of 4,583 kWh, typical of a moderate U.S. climate.

Based on this annual energy savings and a residential electricity cost of $0.078/kWh in 2000, the energy cost savings is $215 per year, giving a simple payback of 11.6 years for a $2,500 system. However, including an O&M cost for the solar system of $25 to $30 annually (based on maintenance once each three years) [8] raises the simple payback to 13 years, a number approaching the system lifetime of 15-30 years. The payback period decreases, however, in states of high electricity cost; for example, above $0.12/kWh (as in much of California or in Hawaii[9]) the payback is 8 years or less, with O&M included.

In comparison with a gas water heater of 60% efficiency, the annual energy savings is $100, making the payback greater than 25 years. Accordingly, the SDHW is not expected to compete well with natural gas. In this GPRA analysis, only displacement of electricity by SDHW is considered.

Solar Pool Heating

The SPH system consists of an unglazed solar collector, usually plastic. Water is circulated using the pool's existing pump, and the pool provides its own thermal storage. A "rule of thumb" is that the area of an SPH collector area must equal about 50 to 100% of the pool area to provide all the pool water heating requirements, and using a pool cover will reduce the SPH area required, so it is reasonable to assume an average of 75%[10]. For the average residential pool size of 576 square feet, as quoted by DOE's Reduce Swimming Pool Energy Costs (RSPEC) program, the required collector size is 432 square feet, the number used in this GPRA analysis.

The typical SPH system costs $3500 to $4000[11], corresponding to $8 to $9 per square foot on average. Another recent article quoted average SPH costs of $8 to $12 per square foot[10]. Note that according to EIA, the average price of the collector alone in 1999 was $2.08 per square foot, presumably wholesale.[5] This would imply that the final cost, including dealer mark-up and installation, is at least three times the collector cost.

The present analysis assumes a typical residential SPH system cost of $4000, or $9.30 per square foot. This may be a little high, which will make the economics and market penetration estimates more conservative.

A typical SPH lifetime is 10 to 15 years[10] for a plastic or rubber collector, with the main problem being degradation by ultraviolet light. Because the system is so simple, there is little or no maintenance beyond that normally given to the pool's circulating system. Accordingly, this analysis assumes zero O&M costs for the SPH.[11]

The energy displacement achieved was estimated by examining the solar resource available in a favorable location, Miami in this analysis. In that location, a latitude tilt collector receives 177 kWh/ft^2 annually of solar insolation. This is equivalent to 604,278 Btu/ft^2 annually. For six months of operation per year (during shoulder months), it was assumed that the solar insolation was 65% of the total annual. Combining this 65% factor with an annual average efficiency of 70%, one calculates a pool heating demand displacement of 275,000 Btu/ft^2/yr. Assuming that gas is displaced and that the gas burner would average an efficiency of 75%, the solar pool collector is assumed to displace 0.367 MMBtu/ft^2/yr. At a natural gas price of $6.72/MMBtu, this yields a payback of about 4 years. Finally, with an average pool size of 432 ft^2, the annual displacement of primary energy is estimated to be 160 MMBtu (1,600 therms) per pool.

Payback periods of about 4 years make the SPH look quite attractive. Although paybacks in this range are seen occasionally in actual practice, they are often somewhat longer, suggesting that either or both of the capital cost or fuel savings are estimated incorrectly. For example, the article in *Home Energy* mentions a Miami pool with retrofit paybacks of 6 years for electricity, 11 years for propane, and 15 years for natural gas; paybacks for new installation are 2.5, 5, and 6.5 years, respectively. However, fuel cost data from the Florida Solar Energy Center[12] indicates that in Central Florida the payback compared with propane would be about 2.2 years, which corresponds to about 3 years for natural gas, depending on the relative fuel costs. The FEMP program reports that SPH paybacks are frequently 2 to 4 years, even for natural gas.[13]

The relatively static nature in prices of residential electricity and natural gas to 2030, to $0.0767/kWh and $6.57/MMBtu, respectively, will keep paybacks constant for future installations.

This analysis does not consider non-residential pools, for which there are certainly some solar applications. For example, the *Solar Today* article mentions recent installations in the Bahamas and Mexico. According to EIA[1], only 10% of the low-temperature collector shipments in 1997 went to non-residential markets, so their impact on national energy savings is small. The size of these commercial or municipal systems can be 10,000 square feet or more, raising questions of siting and pipe runs. Indoor pools in the U.S. now commonly use integrated heat pump systems for water heating, dehumidification, and air conditioning.

Installation Scenario

Solar Domestic Hot Water

According to EIA, a total of 420,000 square feet of solar collectors for medium-temperature liquids was shipped in 1999[1]. This corresponds to 6,500 to 10,500 SDHW units of common size (40 to 64 square feet). Based on data from the Solar Energy Industries Association, the installations for 1998 are estimated to be 7,700 units.

In relative terms, this number is quite low. As ADL[14] points out, the overall target market of electric water heating installations is 4 million annually, of which 1.3 million are in single-family households. The ADL chart, "Proposed program goals are based on realistic market penetrations," goes on to state a target of 25,000 SDHW units for an unspecified year, presumably about 2003. EIA data[15] indicate that in 1983, the peak of the domestic SDHW market, the total square footage of medium-temperature collectors sold domestically was 9 million, corresponding to about 140,000 SDHW units (assuming 64 square feet each) or more. By the late 1980s more than a million units had been installed.[16]

The analysis described here assumes an escalation rate (annual increase in the number of installations in a given year when compared to the number of systems installed in the prior year) that starts at 8% in 2003 and increases to 18% in 2010 (when the low-cost collector is introduced), and then increases more rapidly to a peak of 25% in 2015, after which it decreases to 16% by 2020, and finally declines gradually to 3% in 2030. As a result, the annual installation rate follows an S-shaped curve. This GPRA scenario would achieve the ADL target level of 25,000 installations per year around 2010. The annual installations are estimated to rise to 176,000 by 2020 and 344,000 by 2030.

On a cumulative basis, the GPRA scenario reaches 500,000 installations between 2016 and 2017, somewhat slower than the DOE Million Solar Roofs Program target for solar thermal systems. Cumulative installations exceed one million by 2020 and finally reach nearly 4 million in 2030, or roughly 3-4% of single-family households.

This installation scenario is not directly tied to economics. As discussed above, the simple payback for the SDHW is in the range of 10-13 years. Previous renewable energy analyses for DOE[17] have used market penetration targets based on payback, ranging from 100% for a payback of 1 year or less down to zero penetration for a payback of 20 years or greater. For example, a payback of 3 years corresponds to 89%, 5 years to 66.5%, 7 years to 34%, 10 years to 15%, and 12 years to 9%. This suggests that the projected market penetration is not unreasonable.

Several programs and policies, none of which are modeled in this GPRA analysis, are likely to increase the market attractiveness of SDHW:

- Thirty states were providing financial incentives for solar systems at the end of 1996, according to EIA.[18] The impact of a tax credit is strong, as shown by the history of prior Federal and state tax credits in stimulating the solar water heating market from the mid-1970s to early 1980s. The President's proposed FY2000 Climate Change Budget originally included a 15% tax credit for rooftop solar systems, with a maximum credit of $1,000 for solar water heating systems placed in service from 2000-2004.

- The Energy Efficient Mortgage allows the cost of improvements that reduce the energy bill to be included in the home mortgage, thereby offering a lower interest rate and longer term of repayment that could stimulate the market for SDHW systems on both new and existing homes.

- As a part of utility restructuring and regulatory changes, System Benefit Charges or Renewable Portfolio Standards may be used to promote energy efficiency and renewable energy technologies, including solar water heating, although it is unclear what form these programs might take. On the other hand, to the extent that utility restructuring reduces electricity rates, it makes SDHW less attractive.

Solar Pool Heating

RSPEC data indicate that there are 5.6 million residential pools in the U.S., of which half are assumed to be heated. The National Spa and Pool Institute (NSPI) reports 3.6 million in-ground residential pools. NSPI also reports annual sales of 172,000 new in-ground pools in 1998, up from 120,000 in 1994, or about 5% of the existing stock. In-ground pools are more likely to be heated than above-ground pools. These two sources, taken together, suggest that there are some 2 million heated residential pools in the U.S.

The *Solar Today* and *Home Energy* articles both state that there are currently 300,000 solar pool heaters installed in the U.S. According to both NSPI and EIA[1], 8.1 million square feet of pool collectors were sold in 1999, up from 7.2 million square feet in 1998. For the average system size of 432 square feet, this corresponds to 18,845 SPH systems in 1999. Based on Solar Energy Industries Council data, the installations for 1998 are estimated to be 21,000 units. This amounts to about 1% of the total potential market on an annual basis, or about 10% of the annual new pool sales, suggesting that the SPH market is established but far from saturated.

As discussed above, simple paybacks for SPHs are between one and four years. Therefore, it is reasonable to expect a high level of market penetration. From the method used in previous renewable energy analyses and mentioned above, market adoption rates could be in the range of 90% or higher.

SPH installations are assumed to have a flat 5% escalation rate (compared to prior year levels), comparable to the current growth rate of pools. Starting from the annual installation rate of 21,000 in 1998, this leads to an incremental installation level of 61,000 in 2020 and 100,000 in 2030, still only about half of today's potential market level. Cumulative installations above the 2002 baseline grow to 0.25 million in 2010, 0.75 million in 2020, and 1.5 million in 2030.

Benefits

SDHW displaces electricity and SPH displaces natural gas. Based on the projections of SDHW and SPH installations, primary energy savings are calculated using the GPRA methods and assumptions. In 2010, SPH saves 41 trillion Btu and SDHW saves 3.4 trillion Btu annually, but by 2030 the annual savings have grown to 250 trillion Btu for SPH and 90 trillion Btu for SDHW.

Energy cost savings are calculated from the primary energy savings by using the costs of residential and natural gas from AEO2k, as stated in the *GPRA Data Call: Fiscal Year 2003* (Appendix G).

Carbon savings are calculated using the appropriate EPA emission factors as stated in guidance in the *GPRA Data Call: Fiscal Year 2003*.

References

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2) Arthur D. Little (ADL), *Water Heating Situation Analysis*, November 1996, page 53.
3) Harrison, *Solar Today*, Nov/Dec 1997, pp. 26-29
4) EIA, *Renewable Energy Annual 2000*, Table 12.
5) EIA, *Renewable Energy Annual 2000,* Table 15.
6) ADL, page 53.
7) ADL, page 79 and Appendix A.
8) U.S. Department of Energy, Energy Efficiency and Renewable Energy Network (EREN), Consumer Energy Information: EREC Fact Sheets, "Solar Water Heating," March 1996. www.eren.doe.gov/erec/factsheets/solrwatr.html
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11) Ken Sheinkopf, *Solar Today*, Nov/Dec 1997, pp. 22-25.
12) Florida Solar Energy Center, www.flasolar.com/gas.htm

13) U.S. Department of Energy, Federal Energy Management Program, Federal Technology Alert, "Solar Water Heating," May 1996. www.eren.doe.gov/femp/prodtech/sw_water.html
14) ADL, page 82.
15) Energy Information Administration, *Renewable Energy Annual 1995*, DOE/EIA-0603(95), December 1995, p. 27; 1990 *Statistical Abstract*, Table 583.
16) U.S. Department of Energy, *The Potential of Renewable Energy: An Interlaboratory White Paper*, SERI/TP-260-3674, March 1990.
17) SAIC, Renewable Energy Market Penetration Model, 1990; based on Lilian and Johnston, *Active Program Requirements Research*, 1980. See also SAIC, "Quantitative Rational for the Active Solar Technologies Program," ca. 1996.
18) EIA, *Renewable Energy Annual 1998*, page 27.

FY2003 GPRA METRICS
SOLAR PROGRAM
SUB-PROGRAM: PHOTOVOLTAICS

	2007	2010	2015	2020	2025	2030
Market Penetration Estimate (Cumulative GW installed since 2002)						
Least Cost	0.10	0.18	0.34	0.50	0.67	0.84
Green	0.01	0.14	0.43	0.67	0.78	0.96
Million Solar Roofs Initiative	0.37	0.94	2.71	4.63	6.56	8.48
Total	0.50	1.25	3.45	5.80	8.10	10.5
Annual Benefits						
Energy Displaced (quads)	0.01	0.02	0.05	0.10	0.10	0.15
Direct Electricity Displaced (billion kWh)	0.85	2.30	6.25	10.5	14.5	19.0
Energy Cost Savings (billions of 1999 $)	0.02	0.05	0.10	0.20	0.35	0.45
Carbon Displaced (MMCTE)	0.20	0.40	1.05	1.60	2.25	2.90
Technology Indicators*						
Cost ($/kW)	3,750	2,960	2,300	1,740		
Capacity Factor (%)	20.6	20.6	20.6	20.6		
Levelized Cost of Energy (cents/kWh in constant 1997$)	19.1	14.3	11.3	8.8		
*Based on weighting of 25% Central Station and 75% Buildings and Structures in 2000, changing to 35% Central Station and 65% Buildings and Structures by 2015. *Technology Characterization* data used for NEMS analysis (this report is currently being updated and the values may change).						

Table 1. Summary of Photovoltaic Analysis

Market Segments

In FY 2003, the photovoltaic program will continue both its R&D program and the Million Solar Roofs (MSR) initiative. The MSR initiative is viewed as being an important stimulus for early market penetration for PV, and the analysis of benefits of the FY 2003 program confirms the importance of MSR.

! Green Power - PV has an important role to play in the future green power market. However, at present, because it is significantly more expensive to install than several other green power options, few utilities or energy service providers are likely to choose PV as a way of meeting customer demand for green power. The Green Power Model reflects this fact by predicting very little penetration by PV in the green power market. The Million Solar Roofs initiative targets the application of this technology to compete with retail electricity prices, not the very low competitive grid prices. The realization of MSR goals for PV, 600,000 systems installed by 2010, form the basis for the power penetration projected for MSR that are added to the Green Power Model projections to calculate FY 2003 benefits. Table 2 contains the MSR projections. Projections beyond 2010 assume declining annual growth rates, as would be expected to occur after the end of a major initiative. Table 1 shows that the projection for PV green power in 2020 is 0.43 GW.

! Least Cost Power - This segment is unlikely to provide much market opportunity for PV due to the high COEs projected for the foreseeable future. To develop this estimate, NEMS was run using a composite cost and performance trajectory, reflecting the lowest COE in a given period, taken from the *Renewable Energy Technology Characterizations.*

! Million Solar Roofs Initiative - The Million Solar Roofs initiative targets the application of this technology to compete with retail electricity prices, not the very low competitive grid prices. The realization of MSR goals for PV, 600,000 systems installed by 2010, form the basis for the power penetration projected for MSR that are added to the Green Power Model projections to calculate FY 2003 benefits. Table 2 contains the MSR projections. Projections beyond 2010 assume declining annual growth rates, as would be expected to occur after the end of a major initiative.

	Annual Growth Rate (% above prior year)	Incremental Annual Capacity (MW)	Cumulative Capacity above 2002 baseline (MW)
2000	20	25	-
2001	21	30	-
2002	22	37	-
2003	23	45	45
2004	24	56	102
2005	25	70	172
2007	26	89	261
2007	27	113	373
2008	28	144	517
2009	29	186	703
2010	30	242	945
2011	20	290	1,235
2012	15	334	1,569
2013	10	367	1,935
2014	5	385	2,321
2015	0	385	2,706
2016	0	385	3,091
2017	0	385	3,476
2018	0	385	3,861
2019	0	385	4,247
2020	0	385	4,632

Table 2. Million Solar Roofs Program Capacity Projections

Benefits

! Primary Energy Displaced — Photovoltaics displace conventional electricity on a kWh for kWh basis. The lower capacity factor of photovoltaics does mean, however, that the energy production of a GW of PV is not equivalent to the output of the same capacity of conventional coal capacity. In calculating energy displacement an average grid heat rate is assumed according to the *GPRA Data Call: Fiscal Year 2003*, declining over time by about 25% from 10,796 Btu/kWh.

! Energy Cost Savings — Energy cost savings are derived from energy displacement and average costs of producing electricity were used.

! Carbon Displacement — PV systems displace the carbon that would have been emitted by conventional power plants in producing the electricity. Average grid carbon emission factors are used and declining grid heat rates work again to lower the carbon emissions factor.

FY2003 GPRA METRICS
SOLAR PROGRAM
SUB-PROGRAM: CONCENTRATING SOLAR POWER

	2007	2010	2015	2020	2025	2030
Market Penetration Estimates (Cumulative GW installed since 2002)						
Least Cost	0.03	0.04	0.06	0.09	0.21	0.34
Green	0.04	0.21	0.47	0.61	0.66	0.70
Southwest and other CSP initiatives	0.00	0.00	0.25	1.34	2.34	3.26
Total	0.07	0.25	0.80	2.05	3.20	4.30
Annual Benefits						
Energy Displaced (quads)	0.003	0.01	0.04	0.10	0.15	0.25
Direct Electricity Displaced (billion kWh)	0.30	1.40	4.85	14.0	21.5	29.0
Energy Cost Savings ($ billion)	0.01	0.03	0.10	0.30	0.50	0.70
Carbon Displaced (MMCTE)	0.05	0.25	0.80	2.10	3.30	4.45
Technology Indicators*						
Capital Cost ($/kW$_{nameplate}$) Capital Cost ($/kW$_{peak}$)	2,440 1,160	2,605 965	2,565 950	2,525 935		
Capacity Factor (%)	52	65	71	77		
Levelized Cost of Energy (cents/kWh in constant 1997$)	7.7	5.2	4.7	4.2		
*Power tower *Technology Characterization* data used for NEMS analysis as representing lowest-cost COE trajectory (this report is currently being updated and the values may change).						

Table 1. Summary of Concentrating Solar Power Analysis

Market Segments

Benefits resulting from the FY 2003 Concentrating Solar Power (CSP) program will come in three market segments.

! Green Power - Modest amounts of CSP are projected by the Green Power Model to be installed, as shown in Table 1. For this analysis, trough, dish and power tower technologies were considered. The trough and dish systems were assumed to be viable for all regions of the country, although significant cost penalties for low insolation levels were assumed for many regions of the country. Power towers were assumed to be applicable only to the southern regions of the country, and were excluded from competing throughout the rest of the country. The cost and performance data in the *Renewable Energy Technology Characterizations* were used for both.

! Least Cost Power - Estimates of CSP penetration into this segment were made using NEMS. NEMS compares the cost of energy from CSP systems to all available generating technologies, both conventional and renewable. For this analysis, NEMS was run using the Power Tower cost and performance trajectory taken from the *Renewable Energy Technology Characterizations*. At the time of this analysis, the CSP program was preparing a revised characterization of trough technology. However, that characterization was not used because the work had not yet been peer-reviewed. Upon closer examination of the draft trough characterization, it was determined that the new trough numbers were still higher than the very aggressive cost projections for power tower systems.

! Other Market Segments -- The Southwest initiative targets the application of CSP technologies to specific areas in the southwest United States that have high quality solar resources. The initiative has a stated goal of 1 GW by 2006, however due to the very recent adoption of this initiative, the capacity additions forecasted for this initiative occurs from 2015 to 2030.

Benefits

! Primary Energy Displaced - CSP systems displace conventional electricity on a kWh for kWh basis. In calculating energy displacement, an average grid heat rate, which declines over the analysis period from the current 10,796 Btu/kWh by about 25%, is assumed.

! Energy Cost Savings — Energy cost savings are derived directly from energy displacement, multiplied by the average electric generators cost of fossil fuels. Energy prices and fuel mix from the GPRA Data Call: Fiscal Year 2003 were used.

! Carbon Displacement — CSP systems displace the carbon that would have been emitted by conventional power plants in producing the electricity. For this calculation, average grid carbon emission factors heat rates, as provided in the GPRA Data Call: Fiscal Year 2003 (see Appendix D) were used.

FY2003 GPRA METRICS
BIOMASS POWER

	2007	2010	2015	2020	2025	2030
Market Penetration Estimates (Cumulative GW installed since end of 2002)						
Gasification	0.30	0.76	1.32	1.53	1.93	2.37
Co-firing	3.82	6.15	7.27	8.76	10.1	11.4
Direct Fired	0.05	0.09	0.17	0.21	0.23	0.24
Total	4.15	7.00	8.75	10.5	12.5	14.0
Annual Benefits						
Fossil Fuel Energy Displaced* (quads)	0.35	0.55	0.70	0.80	0.95	1.05
Direct Electricity Displaced** (billion kWh)	2.45	5.95	10.5	12.0	15.0	18.0
Energy Cost Savings ($ billion)	-0.40	-0.70	-0.85	-1.00	-1.15	-1.30
Non-energy Cost Savings ($ billion)	0.09	0.15	0.15	0.15	0.20	0.20
Carbon Displaced (MMCTE)	8.60	14.0	17.0	20.5	23.5	27.0
* Biopower benefits are cited in terms of Fossil Fuel Energy Displaced because biomass has energy content associated with it. ** Biomass Direct Electricity Displaced does not include generation from Co-firing capacity, as this does not displace new capacity, but is rather a fuel switch for existing or planned capacity.						
Technology Indicators*						
Cost ($/kW)	1,580	1,460	1,350	1,260		
Capacity Factor (%)	80	80	80	80		
Levelized Cost of Energy (cents/kWh in constant 1997$)	6.3	6.1	5.8	5.4		
*Gasification *Technology Characterization* data used for NEMS analysis (this report is currently being updated and the values may change). Levelized COE includes feedstock cost of $2.50/GJ at a heat rate of 9730 kJ/kWh in 2005 and 2010 and of 8760 kJ/kWh in 2015 and 2020.						

Table 1. Summary of Biopower Analysis

Market Segments
Biopower systems are expected to penetrate in the least cost, green power markets, and as a lower cost fuel-switch for coal in co-firing applications. This expectation is due largely to biopower's competitive cost of energy. Three market segments were considered for this analysis:

1) Green Power — For this analysis, Gasification and Direct Fired technologies were considered. Gasification is an emerging technology that is expected to penetrate modestly in the Green Power market segment. Direct Fired biopower is a well-established technology, expected to be used primarily in co-generation applications at industrial locations, but also expects some penetration through the Green Power market. Because biomass-generated electricity is so competitive economically and the resource widely available, it is projected to be installed as a green power option in every region of the country. These estimates were made using the Green Power Market Model. Due to the downward revisions in the assumptions of market opportunity and participation in the Green Power Market Model, the estimates of green power capacity additions have been lowered significantly, when compared to last year's results. The cost and performance data in the *Renewable Energy Technology Characterizations* were used for both technologies (this report is currently being updated and the values may change).

2) Least Cost Power — Gasification is the emerging technology modeled in NEMS, representing the most likely technology configuration to be installed in future utility-scale biopower systems. Additional projections of least cost gasification capacity were added to the NEMS portion, based on a review of the ADL report, *Aggressive Growth in the Use of Bio-derived Energy and Products in the United States by 2010*.

3) Other Market Segments — Co-firing in coal power plants is a well-established technology that can be a very cost-effective option, if the biomass feedstock is available. A significant opportunity exists to retrofit existing coal boilers to co-fire biomass with coal. The co-firing capacity additions are based on a review of the ADL report, *Aggressive Growth in the Use of Bio-derived Energy and Products in the United States by 2010*. A baseline of 400 MW in 2002 is assumed, and capacity is projected to be about 9,000 MW by 2020.

Tables 2 and 3 provide definitions of the full range of biopower feedstocks and conversion processes.

Benefits are calculated assuming that the gasification technology replaces a natural gas-fired turbine, the Direct Fired technology displaces a coal boiler, and that Co-firing uses biomass as a fuel switch for more costly coal. The industrial co-generation applications are accounted for under the Distributed Energy Resources program, and the biopower program is not given any credit for biomass cogeneration. The results of the analyses and key technology indicators are shown in Table 1. The results of the GPRA 2003 analysis have increased in comparison to the GPRA 2002 reported figures, especially in relation to the gasification and co-firing projections.

FEEDSTOCKS AND CONVERSION PROCESSES/TECHNOLOGIES FOR THE GENERATION OF BIOMASS POWER[1]

Table 2: Conversion of Feedstock to Fuel for Electricity Generation[2][3

	Homo-genization[4]	Gasification (Syngas)	Anaerobic Digestion of Organic Residues & Wastes (Biogas)	Anaerobic Digestion of Clean Fraction of Municipal Solid Waste (Landfill Gas)	Pretreatment, Hydrolysis & Fermentation (Ethanol)	Ester ification (Biodiesel)	Fast Pyrolysis (Bio-oil)	Processing of Syngas (Methane)	Fischer-Tropsch (FT) Synthesis from Syngas (Liquid Fuels)	Direct Microbial Conversion from Syngas (Ethanol)	Synthesis from Syngas (Methanol)	Thermo-chemical Reforming (Reformate)	Purification[5] (Hydrogen)
Agricultural Residues													
Corn Stover	1	2	1		2		2	3	3	3	3	2,3,4	3,4,5
Wheat Straw	1	2	1		2		2	3	3	3	3	2,3,4	3,4,5
Rice Husks	1	2	1		2		2	3	3	3	3	2,3,4	3,4,5
Bagasse	1	2	1		2		2	3	3	3	3	2,3,4	3,4,5
Other Ag. Res.	1	2	1		2		2	3	3	3	3	2,3,4	3,4,5
Vegetable Oils													
Soybean Oil						1						2,3,4	3,4,5
Rapeseed/Canola						1						2,3,4	3,4,5
Mustard Seed Oil						1						2,3,4	3,4,5
Other Oils						1						2,3,4	3,4,5
Forest Residues	1	2			2		2	3	3	3	3	2,3,4	3,4,5
Forest Thinnings[6]	1	2			2		2	3	3	3	3	2,3,4	3,4,5
Energy Crops													
Switchgrass	1	2			2		2	3	3	3	3	2,3,4	3,4,5
Willow (coppice wood)	1	2			2		2	3	3	3	3	2,3,4	3,4,5
Poplar (single-stem wood)	1	2			2		2	3	3	3	3	2,3,4	3,4,5
Other Energy Crops	1	2			2		2	3	3	3	3	2,3,4	3,4,5
Wastes													
Paper, Yard, & Food	1	2	1	1	2		2	3	3	3	3	2,3,4	3,4,5
Waste Wood	1	2	1	1	2		2	3	3	3	3	2,3,4	3,4,5
Animal Manure	1		1				2					2,3,4	3,4,5
Sewage Sludge	1		1				2					2,3,4	3,4,5
Mill Residues/Sawdust	1	2	1	1	2		2	3	3	3	3	2,3,4	3,4,5
Bio-Waste Oil & Grease						1						2,3,4	3,4,5
Other Bio-Waste	1	2	1	1	2		2	3	3	3	3	2,3,4	3,4,5

FEEDSTOCKS AND CONVERSION PROCESSES/TECHNOLOGIES FOR THE GENERATION OF BIOMASS POWER[1]

Table 3: Conversion of Fuel to Electricity[7]

	Steam Turbine (ST) System[10]	Cofiring with Coal in an ST System	Combustion Turbine[11]	Combined Cycle Gas Turbine[12]	Integrated Gasification Combined Cycle	Spark Ignition Direct Injection[13]	Compression Ignition Direct Injection[14]	Stirling Cycle	PEM	PAFC	MCFC	SOFC	AFC
Agricultural Residues													
Corn Stover	1	1	1,3	1,3	3	2		1,2,3	3,4,5	3,4,5	2,3,4	2,3,4	3,4,5
Wheat Straw	1	1	1,3	1,3	3	2		1,2,3	3,4,5	3,4,5	2,3,4	2,3,4	3,4,5
Rice Husks	1	1	1,3	1,3	3	2		1,2,3	3,4,5	3,4,5	2,3,4	2,3,4	3,4,5
Bagasse	1	1	1,3	1,3	3	2		1,2,3	3,4,5	3,4,5	2,3,4	2,3,4	3,4,5
Other Ag. Res.	1	1	1,3	1,3	3	2		1,2,3	3,4,5	3,4,5	2,3,4	2,3,4	3,4,5
Vegetable Oils													
Soybean Oil			1	1			1	1,2,3	3,4,5	3,4,5	2,3,4	2,3,4	3,4,5
Rapeseed/Canola			1	1			1	1,2,3	3,4,5	3,4,5	2,3,4	2,3,4	3,4,5
Mustard Seed Oil			1	1			1	1,2,3	3,4,5	3,4,5	2,3,4	2,3,4	3,4,5
Other Oils			1	1			1	1,2,3	3,4,5	3,4,5	2,3,4	2,3,4	3,4,5
Forest Residues	1	1	3	3	3	2,3		1,2,3	3,4,5	3,4,5	2,3,4	2,3,4	3,4,5
Forest Thinnings[6]	1	1	3	3	3	2,3		1,2,3	3,4,5	3,4,5	2,3,4	2,3,4	3,4,5
Energy Crops													
Switchgrass	1	1	3	3	3	2		1,2,3	3,4,5	3,4,5	2,3,4	2,3,4	3,4,5
Willow (coppice wood)	1	1	3	3	3	2		1,2,3	3,4,5	3,4,5	2,3,4	2,3,4	3,4,5
Poplar (single-stem wood)	1	1	3	3	3	2		1,2,3	3,4,5	3,4,5	2,3,4	2,3,4	3,4,5
Other Energy Crops	1	1	3	3	3	2		1,2,3	3,4,5	3,4,5	2,3,4	2,3,4	3,4,5
Wastes													
Paper, Yard, & Food	1	1	1,3	1,3	3	2		1,2,3	3,4,5	3,4,5	2,3,4	2,3,4	3,4,5
Waste Wood	1	1	1,3	1,3	3	2		1,2,3	3,4,5	3,4,5	2,3,4	2,3,4	3,4,5
Animal Manure		1	1	1					3,4,5	3,4,5	2,3,4	2,3,4	3,4,5
Sewage Sludge		1	1	1					3,4,5	3,4,5	2,3,4	2,3,4	3,4,5
Mill Residues/Sawdust	1	1	1,3	1,3	3	2		1,2,3	3,4,5	3,4,5	2,3,4	2,3,4	3,4,5
Bio-Waste Oil & Grease			1	1			1	1,2,3	3,4,5	3,4,5	2,3,4	2,3,4	3,4,5
Other Bio-Waste	1	1	1,3	1,3	3	2			3,4,5	3,4,5	2,3,4	2,3,4	3,4,5

Biomass Definition:

Organic matter, including forest thinnings, forest and mill residues, agricultural residues, agricultural crop-derived oils, wood and wood wastes, animal wastes, livestock operation residues, aquatic plants, fast-growing trees and plants, and municipal and industrial wastes.

Notes to tables:

(1) Marked cell show the generally recognized compatibility of feedstocks with processes and technologies (i.e. all plausible, but not all possible, combinations). Series of marked cells in rows should not necessarily be construed, however, to indicate distinct pathways from feedstock to electricity generation.

(2) These processes are sometimes the only step in conversion of feedstock to fuel, and are sometimes used in combination to prepare fuel that is used for power generation. A mark of "1" indicates a first-step process performed on a feedstock. A mark of "2" indicates a process that is typically the second step (for example, processing done after a first step of homogenization of a feedstock). A mark of "3" indicates a process that is typically a third step, and a mark of "4" indicates a process that is typically a fourth step, and a mark of "5" indicates a process that is typically a fifth step. More than one number in a cell indicates a process that can represent different step numbers in different pathways.

(3) Headings in this table refer to processes for converting feedstocks for eventual use in electricity generation. Products of these processes are listed in parentheses at the end of headings.

(4) Homogenization results in chipped, chopped, ground, baled, cubed, or pelletized feedstock.

(5) Purification of gases typically is focused on removal of carbon monoxide; Alkaline fuel cells, however, are particularly sensitive to carbon dioxide.

(6) Includes live trees cleared for fire suppression and bioenergy, that is not strictly speaking a residue of timber harvesting.

(7) A mark of "1" indicates a feedstock that requires one processing step to create a fuel suitable for use with the specified power generation technology. A mark of "2" indicates that 2 processing steps are required, etc. More than one number in a cell indicates that fuels suitable for the specified technology can be created in differing numbers of steps.

(8) Each of these technologies produces some waste heat and can be employed in Combined Heat & Power (CHP), or cogeneration, systems.

(9) PEM = Proton Exchange Fuel Cell; PAFC = Phosphoric Acid Fuel Cell; MCFC = Molten Carbonate Fuel Cell; SOFC = Solid Oxide Fuel Cell; AFC = Alkaline Fuel Cell

(10) This is also known as direct firing in a boiler connected to a steam turbine, and includes cofiring with coal and other fossil fuels in steam turbine systems (Rankine Cycle). Cofiring with coal has been broken out as a separate item because it has been the focus of considerable research and testing activity, but cofiring with other fossil fuels is possible (thought it may require additional processing steps for a feedstock). In theory, any feedstock could be burned in a boiler to operate a steam turbine, but X's in this table represent the more likely feedstocks to be used for this purpose.

(11) Brayton Cycle. One-step processing of biomass to fuel a combustion turbine indicates the use of biogas or landfill gas, or (in the case of vegetable and waste oil and grease) esterification to biodiesel.

(12) Combines Brayton and Rankine Cycles. One-step processing of biomass to fuel the combustion turbine step of this technology indicates the use of biogas or landfill gas, or (in the case of vegetable and waste oil and grease) esterification to biodiesel.

(13) Otto Cycle

(14) Diesel Cycle

FY2003 GPRA METRICS
WIND

	2007	2010	2015	2020	2025	2030
Market Penetration Estimate (Cumulative GW installed since 2002)						
Least Cost	3.85	12.5	29.0	48.5	58.5	65.0
Green	1.30	2.40	3.95	4.45	4.65	4.85
Distributed	Included in green power					
Total	5.0	15.0	33.0	53.0	63.0	70.0
Annual Benefits						
Energy Displaced (quads)	0.20	0.55	1.10	1.70	1.95	2.10
Direct Electricity Displaced (billion kWh)	20.0	62.5	135	215	250	270
Energy Cost Savings ($ billion)	0.40	1.20	2.65	4.55	5.65	6.50
Carbon Displaced (MMCTE)	4.10	11.5	22.0	33.0	38.0	41.0
Technology Indicators*						
Cost ($/kW)	875	830	810	785		
Capacity Factor (%)	44.2	47.1	46.0	46.3		
Levelized Cost of Energy (cents/kWh in constant 1997$)	2.8	2.4	2.5	2.3		
**Technology Indicators* data represents a weighted average of new wind turbine characteristics for Class 4 (5.8 m/s average wind speeds) and Class 6 (6.7 m/s) sites, as defined by program planning documents for the Low Wind Speed Turbine project. Weighting changes from 20/80 for class 4/class 6 in 2003 to 75/25 in 2030.						

Table 1. Summary of Wind Analysis

Market Segments

Wind technologies are expected to be installed in two market segments:

! Least Cost Power - This segment has traditionally been considered to have the largest potential for market penetration (as measured by rated capacity) for wind energy. Market penetration estimates were developed using NEMS, which competes wind against all other generators in this segment. The NEMS analyses were performed by LBL. Green power estimates were explicitly included in NEMS prior to the least cost runs because NEMS does not yet effectively predict penetration into that segments. NEMS was run. Results of the NEMS runs are presented in Table 1.

A number of changes were made to the wind sub-module in NEMS both this year and last. The changes that have been implemented this year include re-characterizing low wind speed turbines performance and cost trajectories using wind technology characteristics from the program planning documents for the Low Wind Speed Turbine project developed by DOE and EPRI, as well as the weighting of class 4 vs. class 6 resources that future capacity additions will be sited on.

! Green Power - Wind is one of the main competitors in the green power market segment. This market segment and the model used to analyze it are described in Appendix C. Wind, as one of the lowest-cost renewable technologies, competes successfully with the other technologies and thus captures about 62% of the green market in 2020. There are already several examples of wind energy being installed to meet the demands for green power. Results are shown in Table 1. The Green Power Market Model is regional and wind penetrated every region extensively, except for the South Atlantic and East South Central regions.

FY2003 GPRA METRICS
RENEWABLE ENERGY PRODUCTION INCENTIVE

	2007	2010	2015	2020	2025	2030
Annual Benefits						
Energy Displaced (quads)	0.04	0.03	0.03	0.03	0.03	0.03
Energy Cost Savings ($ billion)	0.07	0.07	0.07	0.07	0.08	0.09
Carbon Displaced (MMCTE)	15.0	13.5	12.0	11.5	11.5	11.5

Table 1. Summary of REPI Analysis

Analysis

The analysis of the Renewable Energy Production Incentive (REPI) was performed in the same manner as last year:

1) The REPI program began in FY95. Since then, 8 MW of Tier 1 plants (wind, closed-loop biomass, solar, and geothermal) have been installed. An additional 428 MW of Tier 2 plants (open-loop biomass and landfill gas) have been installed.

2) The analysis assumed that in the final two years of the program (last plant installed in 2003), the same number of plants will be installed. This is the assumed benefit of the FY2003 budget.

3) Tier 1 plants are assumed to operate at 30% capacity factor, because they will likely be wind plants. Tier 2 plants are assumed to run at 90% capacity factor, and to be landfill gas plants.

4) Both types of plant displace the weighted mix of fuels that characterize the utility grid, using factors from *GPRA Data Call: Fiscal Year 2003* (see Appendix D) for energy cost savings and energy displacement.

5) Tier 1 plants will displace carbon at the average grid rate, as specified in the data call, while landfill gas plants will displace both carbon from the fuel and methane from the landfill. A factor of x22 was used for calculation of Carbon Displaced for REPI due to the dominance of Landfill gas plants that qualify for this incentive. Of the 436 MW, 428 MW is Landfill gas plants. Landfill gas plants capture both methane and carbon that would otherwise be released to the atmosphere. Methane lasts significantly longer in the atmosphere than Carbon dioxide and other green house gases, and therefore has a greater impact on climate change. This highly leveraged effect results in a very large carbon displacement for a relatively small installed capacity.

Benefits values are constant into the future years because the benefits continue throughout the life of the plants installed.

FY2003 GPRA METRICS
SOLAR PROGRAM SUPPORT (COMPETITIVE SOLICITATION)

	2007	2010	2015	2020	2025	2030
Market Penetration Estimates (Cumulative GW installed since 2002)						
Total	0.08	0.08	0.08	0.08	0.08	0.08
Annual Benefits						
Energy Displaced (quads)	0.005	0.005	0.005	0.005	0.005	0.005
Direct Electricity Displaced (billion kWh)	0.25	0.25	0.25	0.25	0.25	0.25
Energy Cost Savings ($ billion)	0.004	0.01	0.01	0.01	0.01	0.01
Carbon Displaced (MMCTE)	0.06	0.06	0.06	0.06	0.06	0.06
(Note that although the table shows values of zero, actual values are non-zero, just small.)						

Table 1. Summary of Solar Program Support Analysis

Analysis

These estimates were developed by DOE, and are the same as were prepared for the FY2002 GPRA exercise. No significant changes from the original analysis were found to be necessary to include in the FY2003 analysis. The estimates assume the following for a five-year program:

1) Of a $10 million per year funding, $2M would go to federal facilities, $3M to Native Americans, and $5M to others.
2) Matching funding rates of 3 to 1, 1 to 1, and 3 to 1 were assumed for the three groups, so that total funding available is $8M, $6M, and $20M per year, respectively.
3) For Native Americans and Others, 15% of the first two year's of funding would go toward feasibility studies that do not result in actual installations.
4) Assuming $2000/kW due to remote locations or the use of hybrid technology gives the 81 MW total capacity after the five-year program as shown in Table 1. From that capacity, energy displacement is calculated, assuming a 35% capacity factor, 12,000 Btu/kWh heat rate, and that 1/3 of the fuel displaced is diesel, with the remainder displacing the grid mix of fuels.

FY2003 GPRA METRICS
GEOTHERMAL

	2007	2010	2015	2020	2025	2030
Market Penetration Estimates (Cumulative GW installed since the end of 2002)						
Least Cost	3.02	4.74	5.07	5.14	5.32	5.49
Green	0.11	0.26	0.52	0.69	0.75	0.82
Enhanced Geothermal Systems	-	-	1.91	4.17	7.43	10.7
Total	3.15	5.00	7.50	10.0	13.5	17.0
Annual Benefits						
Energy Displaced (quads)	0.25	0.40	0.50	0.65	0.90	1.15
Direct Electricity Displaced (billion kWh)	25.5	41.5	62.5	84.0	115	145
Energy Cost Savings ($ billion)	0.55	0.80	1.25	1.80	2.60	3.50
Carbon Displaced (MMCTE)	5.25	7.70	10.5	13.0	17.5	22.0
Technology Indicators*						
Cost ($/kW)	1,290	1,250	1,200	1,155		
Capacity Factor (%)	93.8	95.0	95.0	96.0		
Levelized Cost of Energy (cents/kWh in constant 1997$)	2.6	2.5	2.3	2.2		
*Weighted average of 90% Flash Geothermal and 10% Binary Geothermal technology data from *Renewable Energy Technology Characterization*. These are provided for comparative purposes only, since the NEMS analysis of geothermal uses site-specific cost data.						

Table 1. Summary of Geothermal Analysis

Market Segments

Geothermal power is expected to be used in three market segments: green power, grid-side least cost, and other market segments. No distributed uses of geothermal were projected, although there is emerging industry interest in such applications, and a new DOE program to explore small-scale modular geothermal plant technology development (<5 MW).

- Green Power – Flash, Binary, and Enhanced Geothermal Systems (EGS) technologies were all modeled as potential geothermal power plants that could be installed to meet the emerging green power market. Flash and Binary technologies compete well within the green power market, with Flash technology out-gaining Binary due to its more attractive cost curve. EGS technologies have significant cost penalties that restrict capacity additions until after 2015, and even then only a very limited amount of EGS power is projected to be built to meet green power demand.

Geothermal plants were limited to the western portion of the United States and were typically the third least expensive option in those regions, behind wind and biopower. Table 1 shows the modest projections for geothermal projected by the Green Power Market Model.

- Least Cost Power - NEMS' modeling of geothermal capacity additions has come under increasing scrutiny in recent years. Recent Annual Energy Outlooks projected that geothermal plants would be installed in "lumps," i.e., a sizeable plant one year and then nothing for several years, then another sizeable lump, etc. It has recently been recognized that one of the original design specifications for the geothermal module was that a waiting period of 4 years was appropriate between new plants at a particular location, to allow the performance of the new installation to be confirmed prior to embarking on another installation. It is exactly this periodicity that NEMS was demonstrating with its lumpy projections.

- Other Market Segments - The program prepared an estimate of EGS penetration in the post-2010 timeframe. This estimate was included in recognition of the assumed success of the newly initiated EGS R&D program. Approximately 500 MW per year are projected to come from EGS installations after 2010. EGS are not modeled in NEMS because that technology is in the early stages of development, however the program is working to have this technology modeled directly by NEMS for next year's analysis.

For the GPRA 2003 analysis LBNL has eliminated the construction delay between projects (both large and small) at individual sites. LBNL has also implemented a code change that better represents the mix of high and low resource areas that are represented in NEMS.

FY2003 GPRA METRICS
HYDROGEN

	2007	2010	2015	2020	2025	2030
Market Penetration Estimates (Cumulative since 2002)						
Vehicles (in thousands)	250	940	2,700	5,600	8,450	11,350
Stationary Power (in GW)	0.00	0.00	3.45	6.85	10.0	13.5
Annual Benefits						
Energy Displaced (quads)	0.01	0.05	0.25	0.50	0.75	1.00
Energy Cost Savings ($ billion)	-0.10	0.20	1.55	3.85	6.10	8.40
Carbon Displaced (MMCTE)	0.55	2.00	8.65	18.0	27.5	37.5
Technology Indicators						
Stationary Power- Molten Carbonate Fuel Cell Cost ($/kW)	1,300	1,000	1,000	1,000		
Stationary Power- MCFC Capacity Factor (%)	72.0	75.0	75.0	75.0		
SUV Fuel Cell Vehicle Cost ($)	50,000	35,000	33,750	31,250		
Car Fuel Cell Vehicle Cost ($)	50,000	40,000	27,000	26,000		

Table 1. Summary of Hydrogen Analysis

Market Segments

Two segments were examined for hydrogen technology use: 1) hydrogen fuel cell vehicles, and 2) stationary power generation resulting from hydrogen fuel cell use in combined heat and power applications in the industrial and commercial sectors.

The vehicle analysis looks at sport utility vehicle (SUV) and passenger car market penetration. For cars, the analysis focuses on markets created by ZEV requirements in California, New York, and Massachusetts. For SUVs, market penetration is assumed for high-value markets outside of the ZEV mandate states. The high-value market represents "green-consumers" willing to pay premium prices for low-emission, high-efficiency vehicles. In particular, the SUV market, consisting of light trucks used primarily as passenger vehicles, is seen as offering a potential opening for high-priced, status-oriented technologies.

A second market segment examined is for fuel cell use in CHP applications in the industrial and residential sectors. With the advent of electricity and energy market restructuring, new opportunities will open-up for distributed or on-site generation of electricity from natural-gas fueled technologies. Additionally, power quality and reliability have become increasingly valued for many industrial and commercial processes. The installation of stationary power fuel cells provides a cost-effective way for companies to ensure that their power supply is high quality and will not be disrupted during grid outages.

Fuel Cell Vehicles

System Definition

The analysis assumes that future fuel cell automobiles will use onboard hydrogen storage, rather than storing a liquid fuel (methanol or gasoline) onboard and reforming it onboard. Currently, automobile manufacturers are examining both ways of providing hydrogen to a fuel cell engine. The direct hydrogen fuel cell (that is, hydrogen stored onboard) has several advantages over onboard reforming of a liquid fuel: greater onboard fuel efficiency, as there are no reformer losses; ultimately greater overall energy efficiency, as large-scale central or distributed stationary reformers can be designed more efficiently than smaller, vehicle mounted models; true zero emissions performance, where an onboard reformer will produce CO_2, some NO_x, and some CO, a direct hydrogen system will produce only water; and longer fuel cell life/better fuel cell performance resulting from the lack of impurities that can "poison" a PEM stack. The primary obstacles to direct hydrogen fuel cell vehicles are lower energy specific fuel storage capacity and the high cost of establishing a hydrogen-refueling infrastructure. However, analyses have shown that current hydrogen storage technologies, coupled with the increased efficiency of fuel cell technologies can produce a vehicle with a commercially acceptable cruising range.

System Economics

The analysis divided the potential market into two sub-segments.

1) The first, for passenger cars, is the limited market available in states that have mandated the use of Zero Emissions Vehicles (ZEVs). Those states are California, Massachusetts, and New York. For passenger cars, it is assumed that the mandate will be for 10% of all new cars to be ZEVs by 2010. In 2000, this gives a three state ZEV market of about 150,000 vehicles. Of these, it was assumed that only 40% would be “true ZEV” vehicles. A technical readiness factor of 50% in 2005 was applied to account for a slowly growing early market development. Given those mandates, which define the total potential market size, it remains to allocate that segment among the potential ZEV technology options. For passenger cars, it was assumed that the only viable alternative was electric passenger vehicles. Figure 1 shows the assumed characteristics of each of these. From these characteristics, a cost of operation per passenger mile was calculated. Those results are shown in Table 2.

$/mile	2005	2010	2015	2020
Fuel Cell Car	1.37	0.57	0.40	0.38
Electric Car	0.77	0.55	0.45	0.34

Table 2. Cost of operation for passenger cars.

From these costs of operation, market shares were calculated. A logit function formulation using a lambda of 3.2 was used. Results for the passenger car segments are shown in Table 3.

Market Share (%)	2007	2010	2015	2020
Fuel Cell Car	20	47	59	40
Electric Car	80	53	41	60

Table 3. Market Share for passenger cars in the ZEV-mandate markets

Figure 1. Passenger Car Characteristics

		Current Baseline	2007	2010	2015	2020
Fuel Cell Passenger Car (direct hydrogen)						
Discount rate	pct/year	10%	10%	10%	10%	10%
System life	yrs	9	9	9	9	9
Vehicle cost	$	$99,999	$99,999	$40,000	$27,000	$26,000
Depreciation	pct/year	15%	15%	15%	15%	15%
Fuel cost	$/mmBtu	$30	$18	$16	$14	$12
Heat content of gasoline	mmBtu/gal	0.123	0.123	0.123	0.123	0.123
Equivalent fuel cost	$/gal	$3.70	$2.25	$1.95	$1.70	$1.45
Annual mileage	mi/year	12,000	12,000	12,000	12,000	12,000
Fuel use	mpg	50	69	75	77	80
Maintenance cost	$/year	$150	$150	$150	$150	$150
Maintenance escalation	pct/year	10%	10%	10%	10%	10%
Electric Passenger Car						
Discount rate	pct/year	10%	10%	10%	10%	10%
System life	yrs	9	9	9	9	9
Vehicle cost	$	$99,999	$47,600	$38,000	$30,000	$22,000
Depreciation	pct/year	15%	15%	15%	15%	15%
Electricity cost	$/mmBtu	$0.080	$0.078	$0.077	$0.073	$0.071
Heat rate	kWh/mmBtu	293	293	293	293	293
Heat content of gasoline	mmBtu/gal	$0.123	$0.123	$0.123	$0.123	$0.123
Fuel cost	$/gal	$2.90	$2.80	$2.80	$2.65	$2.55
Annual mileage	mi/year	12,000	12,000	12,000	12,000	12,000
Fuel use	mpg	70	73	75	77	80
Maintenance cost	$/year	$150	$150	$150	$150	$150
Maintenance escalation	pct/year	10%	10%	10%	10%	10%

Note - a cost of $99,999 connotes that the technology is not commercially available yet, and that costs are largely unknown, benefits of consumer investment from vehicles introduced in these years are calculated based on a cost of $50,000 per vehicle.

2) The second market sub-segment considered was the broader competitive national market for new SUVs. In 2000, some 5.8 million SUVs will be sold nationally. It is difficult to predict how this market will evolve. For this analysis, it was assumed that the national market for Alternative Fuel Vehicles (AFVs) evolves over time, beginning at 10% of the total new SUV market, and growing to 50% by 2020. The 30% value assumed in 2010 corresponds to the Energy Policy Act of 1992 goal for AFVs. A second factor was then introduced to represent consumer lag in adoption of ZEVs in the AFV market due to unfamiliarity with ZEV technology. Figure 2 lists the assumed characteristics of SUVs used for this analysis. Within this growing portion of the national market, it is assumed that prospective purchasers will then make their decision based on operating cost per mile, as listed in Table 4. Market shares of the ZEV portion of the AFV segment are then allocated among the three ZEV SUV options (fuel cell, diesel hybrid, and electric), as also seen in Table 4. No national market for passenger car ZEVs was assumed since the difficulties and cost of integrating fuel cells into passenger cars are significant.

Figure 2. SUV Characteristics

		Current Baseline	2007	2010	2015	2020
Fuel Cell SUV						
Discount rate	pct/year	10%	10%	10%	10%	10%
System life	yrs	9	9	9	9	9
Vehicle cost	$	$99,999	$99,999	$35,000	$33,750	$32,250
Depreciation	pct/yer	15%	15%	15%	15%	15%
Fuel cost	$/mmBtu	$30	$30	$16	$14	$12
Heat content of gasoline	mmBtu/gal	0.123	0.123	0.123	0.123	0.123
Equivalent fuel cost	$/gal	$3.70	$3.70	$1.95	$1.70	$1.45
Annual mileage	mi/year	15,000	15,000	15,000	15,000	15,000
Fuel economy	mpg	40	40	40	46	50
Maintenance cost	$/year	$158	$158	$158	$158	$158
Maintenance escalation	pct/year	10%	10%	10%	10%	10%
Electric SUV						
Discount rate	pct/year	10%	10%	10%	10%	10%
System life	yrs	9	9	9	9	9
Vehicle cost	$	$99,999	$99,999	$37,500	$36,250	$35,000
Depreciation	pct/year	15%	15%	15%	15%	15%
Electricity cost	$/mmBtu	$0.080	$0.078	$0.077	$0.073	$0.071
Heat rate	kWh/mmBtu	293	293	293	293	293
Heat content of gasoline	mmBtu/gal	$0.123	$0.123	$0.123	$0.123	$0.123
Fuel cost	$/gal	$2.88	$2.81	$2.78	$2.64	$2.56
Annual mileage	mi/year	12,000	12,000	12,000	12,000	12,000
Fuel use	mpg	70	72	80	80	80
Maintenance cost	$/year	$90	$90	$90	$90	$90
Maintenance escalation	pct/year	10%	10%	10%	10%	10%
Diesel Hybrid SUV						
Discount rate	pct/year	10%	10%	10%	10%	10%
System life	yrs	9	9	9	9	9
Vehicle cost	$	$99,999	$99,999	$32,500	$31,250	$30,000
Depreciation	pct/yer	15%	15%	15%	15%	15%
Heat content of diesel	mmBtu/gal	0.1387	0.1387	0.1387	$0.1387	$0.1387
Fuel cost	$/gal	1.05	1.18	1.19	1.19	1.18
Annual mileage	mi/yr	15,000	15,000	15,000	15,000	15,000
Fuel economy	mpg	38	38	38	40	46
Maintenance cost	$/yr	$158	$158	$158	$158	$158
Maintenance escalation	pct/year	10%	10%	10%	10%	10%

Note - a cost of $99,999 connotes that the technology is not commercially available yet, and that costs are largely unknown, benefits of consumer investment from vehicles introduced in these years are calculated based on a cost of $50,000 per vehicle.

	2007	2010	2015	2020
Market Development Factors				
% of total national market that would consider purchasing a ZEV SUV	24	30 (EPAct goal)	40	50
Technology lag factor (%)	19	40	52	65
Operating Cost ($/mile)				
Fuel Cell SUV	6.52	0.43	0.40	0.37
Diesel Hybrid SUV	6.46	0.39	0.37	0.36
Electric SUV	6.47	0.40	0.39	0.36
Share of Alternative Fuel Vehicles Market (%)				
Fuel Cell SUV	33%	28%	29%	31%
Diesel Hybrid SUV	34%	39%	38%	36%
Electric SUV	34%	34%	33%	34%

Table 4. Market Share for SUVs in the National Market

Market Penetration

Using the methods described above, the market penetration rates calculated are as listed in Table 6.

System Benefits

The market penetration described in Table 5 yields energy savings and emission reductions benefits. The energy savings come from the higher fuel efficiency of the fuel cell compared to a gasoline internal combustion engine. In gasoline equivalents, the efficiency of fuel cells for SUVs is assumed to be 40 miles per gallon in 2000 (rising to 50 mpg in 2020, compared to 20 mpg for gasoline-powered SUVs. The comparable figures are 50 mpg in 2000 (rising to 73 mpg in 2020) for fuel cell cars, versus 27 mpg for gasoline-powered cars. Annual use is assumed to be 15,000 miles for SUVs and 12,000 miles for cars. These values yield the benefits shown in Table 6.

	2007	2010	2015	2020
ZEV Mandate Market				
Passenger Cars	37,000	80,000	224,000	360,000
National High-Value Market				
SUVs	222,000	860,000	2,450,000	5,220,000

Table 5. Cumulative market penetration for hydrogen fuel-cell vehicles

	2007	2010	2015	2020
Energy displaced/year (trillion Btu)	11.5	42.5	135	300
Energy displaced/year (quads)	0.01	0.04	0.14	0.30
Carbon displaced/year (million metric tons)	0.55	2.00	6.15	13.5

Table 6. Annual Benefits of Fuel Cell Use in Transportation Applications

Stationary Power Generation from Combined Heat and Power Applications

System Definition

The application of combined heat and power (CHP) technologies in the industrial and commercial sectors is analyzed under the Distributed Energy Resources (DER) program. However, since hydrogen fuel cell technologies are expected to penetrate this market, the hydrogen program receives a portion of the benefits calculated from the CHP analysis. The commercial introduction of hydrogen fuel cells, in the form of molten carbonate fuel cells (MCFC), is not expected to occur until after 2010. The work done by the hydrogen program contributes to this introduction, and for this reason, the hydrogen program starts receiving benefits from the DER program beginning in 2015. From 2015 to 2030, the portion of DER benefits attributed to the hydrogen program is based on projected budgets and on the expected relative contributions of fuel cell technologies to CHP introduction. Table 7 shows the percent of CHP analysis benefits attributed to the hydrogen program.

	2015	2020	2025	2030
Percentage (%)	18	25	29	32

Table 7. Portion of CHP applications attributed to the Hydrogen Program.

Market Penetration

The market penetration rates calculated for hydrogen fuel cells in the CHP analysis are as shown in Table 8.

System Benefits

The market penetration described in Table 8 yields emissions reductions benefits as listed in Table 9. The emissions displacements occur because of the high efficiency and clean operation of hydrogen fuel cells. Note, however, that the fuel cells are projected to actually increase energy use because their heat rate is projected to be higher than the average grid heat rate in 2010 and beyond.

	2007	2010	2015	2020
Percent of CHP benefits attributed to Hydrogen Program	-	-	18	25
Cumulative Capacity additions of MCFC	-	-	3.5	6.9
MCFC Capacity Factor (%)	72	75	75	75
Generation from MCFC Capacity (millions of kWh)	-	-	22,700	45,000

Table 8. Market Penetration by CHP applications attributed to the Hydrogen Program

	2007	2010	2015	2020
Energy displaced/year (trillion Btu)	0.00	000	95.0	180
Energy displaced/year (quads)	0.00	0.00	0.10	0.18
Carbon displaced/year (million metric tons)	0.00	0.00	2.50	4.65

Table 9. Annual Benefits of CHP applications attributed to the Hydrogen Program

Addendum to Hydrogen GRPA Analysis

After the analysis for GPRA 2003 was completed, the OPT hydrogen program performed an updated assessment to reflect changes in program priorities and expectations, and to better coordinate the OPT response with the OTT response. Those changes were developed too late to be reflected in the Final EERE-level GPRA documentation. However, for completeness, and so the analysis "is not lost," the update is included in the following pages.

Revised HYDROGEN GPRA Analysis

	2007	2010	2015	2020	2025	2030
Market Penetration Estimates (Cumulative since 2002)						
Vehicles (in thousands)	0	0	80	3,750	8,450	11,350
Stationary Power (in GW)	0.00	0.00	1.85	6.85	10.0	13.5
Annual Benefits						
Energy Displaced (quads)	0.00	0.00	0.05	0.40	0.75	1.00
Energy Cost Savings ($ billion)	0.00	0.00	0.35	3.00	6.10	8.40
Carbon Displaced (MMCTE)	0.00	0.00	1.55	13.5	27.5	37.5
Technology Indicators						
Stationary Power- PEM Fuel Cell Cost ($/kW)	1,510	1,300	950	600		
Stationary Power- PEM FC Capacity Factor (%)	72.0	75.0	75.0	75.0		
SUV Fuel Cell Vehicle Cost ($)	99,999	99,999	50,000	31,250		
Car Fuel Cell Vehicle Cost ($)	99,999	99,999	40,000	26,000		

Table 1. Summary of Hydrogen Analysis

Note - a cost of $99,999 connotes that the technology is not commercially available yet, and that costs are largely unknown.

Market Segments

Two segments were examined for hydrogen technology use: 1) hydrogen fuel cell vehicles, and 2) stationary power generation resulting from hydrogen fuel cell use in combined heat and power applications in the industrial and commercial sectors.

The vehicle analysis looks at sport utility vehicle (SUV) and passenger car market penetration. For cars, the analysis focuses on markets created by ZEV requirements in California, New York, and Massachusetts. For SUVs, market penetration is assumed for high-value markets outside of the ZEV mandate states. The high-value market represents "green-consumers" willing to pay premium prices for low-emission, high-efficiency vehicles. In particular, the SUV market, consisting of light trucks used primarily as passenger vehicles, is seen as offering a potential opening for high-priced, status-oriented technologies.

A second market segment examined is for fuel cell use in CHP applications in the industrial and residential sectors. With the advent of electricity and energy market restructuring, new opportunities will open-up for distributed or on-site generation of electricity from natural-gas fueled technologies. Additionally, power quality and reliability have become increasingly valued for many industrial and commercial processes. The installation of stationary power fuel cells provides a cost-effective way for companies to ensure that their power supply is high quality and will not be disrupted during grid outages.

Fuel Cell Vehicles

System Definition

The analysis assumes that future fuel cell automobiles will use onboard hydrogen storage, rather than storing a liquid fuel (methanol or gasoline) onboard and reforming it onboard. Currently, automobile manufacturers are examining both ways of providing hydrogen to a fuel cell engine. The direct hydrogen fuel cell (that is, hydrogen stored onboard) has several advantages over onboard reforming of a liquid fuel: greater onboard fuel efficiency, as there are no reformer losses; ultimately greater overall energy efficiency, as large-scale central or distributed stationary reformers can be designed more efficiently than smaller, vehicle mounted models; true zero emissions performance, where an onboard reformer will produce CO_2, some NO_x, and some CO, a direct hydrogen system will produce only water; and longer fuel cell life/better fuel cell performance resulting from the lack of impurities that can "poison" a PEM stack. The primary obstacles to direct hydrogen fuel cell vehicles are lower energy specific fuel storage capacity and the high cost of establishing a hydrogen-refueling infrastructure. However, analyses have shown that current hydrogen storage technologies, coupled with the increased efficiency of fuel cell technologies can produce a vehicle with a commercially acceptable cruising range.

System Economics

The analysis divided the potential market into two sub-segments.

1) The first, for passenger cars, is the limited market available in states that have mandated the use of Zero Emissions Vehicles (ZEVs). Those states are California, Massachusetts, and New York. For passenger cars, it is assumed that the mandate will be for 10% of all new cars to be ZEVs by 2010. In 2000, this gives a three state ZEV market of about 150,000 vehicles. Of these, it was assumed that only 40% would be "true ZEV" vehicles. A technical readiness factor of 50% in 2005 was applied to account for a slowly growing early market development. Given those mandates, which define the total potential market size, it remains to allocate that segment among the potential ZEV technology options. For passenger cars, it was assumed that the only viable alternative was electric passenger vehicles. Figure 1 shows the assumed characteristics of each of these. From these characteristics, a cost of operation per passenger mile was calculated. Those results are shown in Table 2.

$/mile	2007	2010	2015	2020
Fuel Cell Car	9.99	9.99	0.60	0.38
Electric Car	0.77	0.55	0.45	0.34

Table 2. Cost of operation for passenger cars.
Note - a cost of $9.99/mile connotes that the technology is not commercially available yet, and that costs are largely unknown.

From these costs of operation, market shares were calculated. A logit function formulation utilizing a lambda of 3.2 was used. Results for the passenger car segments are shown in Table 3.

Figure 1. Passenger Car Characteristics

		Current Baseline	2007	2010	2015	2020
Fuel Cell Passenger Car (direct hydrogen)						
Discount rate	pct/year	10%	10%	10%	10%	10%
System life	yrs	9	9	9	9	9
Vehicle cost	$	$99,999	$99,999	$99,999	$40,000	$26,000
Depreciation	pct/year	15%	15%	15%	15%	15%
Fuel cost	$/mmBtu	$30	$18	$16	$14	$12
Heat content of gasoline	mmBtu/gal	0.123	0.123	0.123	0.123	0.123
Equivalent fuel cost	$/gal	$3.70	$2.25	$1.95	$1.70	$1.45
Annual mileage	mi/year	12,000	12,000	12,000	12,000	12,000
Fuel use	mpg	50	69	75	77	80
Maintenance cost	$/year	$150	$150	$150	$150	$150
Maintenance escalation	pct/year	10%	10%	10%	10%	10%
Electric Passenger Car						
Discount rate	pct/year	10%	10%	10%	10%	10%
System life	yrs	9	9	9	9	9
Vehicle cost	$	$99,999	$47,600	$38,000	$30,000	$22,000
Depreciation	pct/year	15%	15%	15%	15%	15%
Electricity cost	$/mmBtu	$0.080	$0.078	$0.077	$0.073	$0.071
Heat rate	kWh/mmBtu	293	293	293	293	293
Heat content of gasoline	mmBtu/gal	$0.123	$0.123	$0.123	$0.123	$0.123
Fuel cost	$/gal	$2.90	$2.80	$2.80	$2.65	$2.55
Annual mileage	mi/year	12,000	12,000	12,000	12,000	12,000
Fuel use	mpg	70	73	75	77	80
Maintenance cost	$/year	$150	$150	$150	$150	$150
Maintenance escalation	pct/year	10%	10%	10%	10%	10%

Note - a cost of $99,999 connotes that the technology is not commercially available yet, and that costs are largely unknown.

Market Share (%)	2007	2010	2015	2020
Fuel Cell Car	0	0	20	40
Electric Car	100	100	80	60

Table 3. Market Share for passenger cars in the ZEV-mandate markets

2) The second market sub-segment considered was the broader competitive national market for new SUVs. In 2000, some 5.8 million SUVs will be sold nationally. It is difficult to predict how this market will evolve. For this analysis, it was assumed that the national market for Alternative Fuel Vehicles (AFVs) evolves over time, beginning at 10% of the total new SUV market, and growing to 50% by 2020. The 30% value assumed in 2010 corresponds to the Energy Policy Act of 1992 goal for AFVs. A second factor was then introduced to represent consumer lag in adoption of ZEVs in the AFV market due to unfamiliarity with ZEV technology. Figure 2 lists the assumed characteristics of SUVs used for this analysis. Within this growing portion of the national market, it is assumed that prospective purchasers will then make their decision based on operating cost per mile, as listed in Table 4. Market shares of the ZEV portion of the AFV segment are then allocated among the three ZEV SUV options (fuel cell, diesel hybrid, and electric), as also seen in Table 4. No national competitive market for passenger car ZEVs was assumed since the difficulties and cost of integrating fuel cells into passenger cars are significant.

Figure 2. SUV Characteristics

		Current Baseline	2007	2010	2015	2020
Fuel Cell SUV						
Discount rate	pct/year	10%	10%	10%	10%	10%
System life	yrs	9	9	9	9	9
Vehicle cost	$	$99,999	$99,999	$99,999	$50,000	$32,250
Depreciation	pct/yer	15%	15%	15%	15%	15%
Fuel cost	$/mmBtu	$30	$30	$16	$14	$12
Heat content of gasoline	mmBtu/gal	0.123	0.123	0.123	0.123	0.123
Equivalent fuel cost	$/gal	$3.70	$3.70	$1.95	$1.70	$1.45
Annual mileage	mi/year	15,000	15,000	15,000	15,000	15,000
Fuel economy	mpg	40	40	40	46	50
Maintenance cost	$/year	$158	$158	$158	$158	$158
Maintenance escalation	pct/year	10%	10%	10%	10%	10%
Electric SUV						
Discount rate	pct/year	10%	10%	10%	10%	10%
System life	yrs	9	9	9	9	9
Vehicle cost	$	$99,999	$99,999	$37,500	$36,250	$35,000
Depreciation	pct/year	15%	15%	15%	15%	15%
Electricity cost	$/mmBtu	$0.080	$0.078	$0.077	$0.073	$0.071
Heat rate	kWh/mmBtu	293	293	293	293	293
Heat content of gasoline	mmBtu/gal	$0.123	$0.123	$0.123	$0.123	$0.123
Fuel cost	$/gal	$2.88	$2.81	$2.78	$2.64	$2.56
Annual mileage	mi/year	12,000	12,000	12,000	12,000	12,000
Fuel use	mpg	70	72	80	80	80
Maintenance cost	$/year	$90	$90	$90	$90	$90
Maintenance escalation	pct/year	10%	10%	10%	10%	10%
Diesel Hybrid SUV						
Discount rate	pct/year	10%	10%	10%	10%	10%
System life	yrs	9	9	9	9	9
Vehicle cost	$	$99,999	$99,999	$32,500	$31,250	$30,000
Depreciation	pct/yer	15%	15%	15%	15%	15%
Heat content of diesel	mmBtu/gal	0.1387	0.1387	0.1387	$0.1387	$0.1387
Fuel cost	$/gal	1.05	1.18	1.19	1.19	1.18
Annual mileage	mi/yr	15,000	15,000	15,000	15,000	15,000
Fuel economy	mpg	38	38	38	40	46
Maintenance cost	$/yr	$158	$158	$158	$158	$158
Maintenance escalation	pct/year	10%	10%	10%	10%	10%

Note - a cost of $99,999 connotes that the technology is not commercially available yet, and that costs are largely unknown, benefits of consumer investment from vehicles introduced in these years are calculated based on a cost of $50,000 per vehicle.

	2007	2010	2015	2020
Market Development Factors				
% of total national market that would consider purchasing a ZEV SUV	24	30 (EPAct goal)	40	50
Technology lag factor (%)	19	40	52	65
Operating Cost ($/mile)				
Fuel Cell SUV	9.99	9.99	0.60	0.37
Diesel Hybrid SUV	6.46	0.39	0.37	0.36
Electric SUV	6.47	0.40	0.39	0.36
Share of Alternative Fuel Vehicles Market (%)				
Fuel Cell SUV	0%	0%	2%	20%
Diesel Hybrid SUV	50%	53%	52%	40%
Electric SUV	50%	47%	46%	40%

Table 4. Market Share for SUVs in the National Market

Note - a cost of $9.99/mile connotes that the technology is not commercially available yet, and that costs are largely unknown.

Market Penetration

Using the methods described above, the market penetration rates calculated are as listed in Table 6.

System Benefits

The market penetration described in Table 5 yields energy savings and emission reductions benefits. The energy savings come from the higher fuel efficiency of the fuel cell compared to a gasoline internal combustion engine. In gasoline equivalents, the efficiency of fuel cells for SUVs is assumed to be 40 miles per gallon in 2000 (rising to 50 mpg in 2020, compared to 20 mpg for gasoline-powered SUVs. The comparable figures are 50 mpg in 2000 (rising to 73 mpg in 2020) for fuel cell cars, versus 27 mpg for gasoline-powered cars. Annual use is assumed to be 15,000 miles for SUVs and 12,000 miles for cars. These values yield the benefits shown in Table 6.

	2007	2010	2015	2020
ZEV Mandate Market				
Passenger Cars	0	0	80,000	360,000
National High-Value Market				
SUVs	0	0	0	3,390,000

Table 5. Cumulative market penetration for hydrogen fuel-cell vehicles

	2007	2010	2015	2020
Energy displaced/year (trillion Btu)	0	0	4.00	200
Energy displaced/year (quads)	0	0	0.004	0.20
Carbon displaced/year (million metric tons)	0	0	0.18	9.00

Table 6. Annual Benefits of Fuel Cell Use in Transportation Applications

Stationary Power Generation from Combined Heat and Power Applications

System Definition

The application of combined heat and power (CHP) technologies in the industrial and commercial sectors is analyzed under the Distributed Energy Resources (DER) program. However, since hydrogen fuel cell technologies are expected to penetrate this market, the hydrogen program receives a portion of the benefits calculated from the CHP analysis. The commercial introduction of hydrogen fuel cells, in the form of proton exchange membrane fuel cells (PEMFC), is not expected to occur until after 2010. The work done by the hydrogen program contributes to this introduction, and for this reason, the hydrogen program starts receiving benefits from the DER program beginning in 2015. From 2015 to 2030, the portion of DER benefits attributed to the hydrogen program is based on projected budgets and on the expected relative contributions of fuel cell technologies to CHP introduction. Table 7 shows the percent of CHP analysis benefits attributed to the hydrogen program.

	2015	2020	2025	2030
Percentage (%)	10	25	29	32

Table 7. Portion of CHP applications attributed to the Hydrogen Program.

Market Penetration

The market penetration rates calculated for hydrogen fuel cells in the CHP analysis are as shown in Table 8.

System Benefits

The market penetration described in Table 8 yields emissions reductions benefits as listed in Table 9. The emissions displacements occur because of the high efficiency and clean operation of hydrogen fuel cells.

	2007	2010	2015	2020
Percent of CHP benefits attributed to Hydrogen Program	-	-	10	25
Cumulative Capacity additions of PEM FC	-	-	1.8	6.9
PEM FC Capacity Factor (%)	72	75	75	75
Generation from PEM FC Capacity (millions of kWh)	-	-	12,100	45,000

Table 8. Market Penetration by CHP applications attributed to the Hydrogen Program

	2007	2010	2015	2020
Energy displaced/year (trillion Btu)	0.00	0.00	50.0	180
Energy displaced/year (quads)	0.00	0.00	0.05	0.18
Carbon displaced/year (million metric tons)	0.00	0.00	1.35	4.65

Table 9. Annual Benefits of CHP applications attributed to the Hydrogen Program

FY2003 GPRA METRICS
DISTRIBUTED ENERGY RESOURCES PROGRAM

	2007	2010	2015	2020	2025	2030
Annual Benefits						
Energy Displaced (quads)	0.40	0.40	0.45	0.55	0.65	0.80
Energy Cost Savings ($ billion)	1.75	2.05	2.60	3.50	4.20	4.85
Direct Electricity Displaced (billion kWh)	40.0	42.0	52.0	67.5	83.5	100
Carbon Displaced (MMCTE)	9.25	10.5	11.5	14.0	17.0	20.0

Table 1. Summary of Overall Distributed Program Analysis

Market Segments

The Distributed Energy Resources (DER) Program sponsors a wide range of research activities. These include: advanced turbines and microturbines, natural gas engines, PEM fuel cells, thermally activated technologies, combined heat and power, transmission reliability, and storage.

Because of the diversity of the program's efforts and the broad array of market opportunities that present themselves to the various DER technologies, OPT has used a simplified approach to calculating the benefits of the DER program. That approach is based on the fact that the overwhelmingly largest benefit will come from the installation of combined heat and power (CHP) systems. Therefore, an analysis of the potential of CHP systems in the U.S. market place was undertaken for GPRA 2003. The results of that analysis were used as a surrogate for the total program benefits. It should be noted that the same approach was used for GPRA 2002, but the analysis performed for last year was much less rigorous.

It is recognized that the OPT hydrogen program contributes to the success of the DER fuel cell activities, and, accordingly, the Hydrogen Program is allocated a small portion of the benefits estimated to be attributable to the use of CHP. That percentage for the Hydrogen Program ranges from 18% in 2015 to 32% in 2030. (see the Hydrogen section of this report).

For the GPRA 2003 benefits analysis, OPT used NEMS commercial and industrial sector CHP (cogeneration) analysis modules. However, EIA's cost and performance projections were replaced by estimates from the Energy Nexus Group. This was the first year that NEMS was used for these calculations and doing so provided a better representation of the integrated effect on the total energy system that extensive CHP implementation would have.

Results

The results of the NEMS analysis are shown in Table 2. NEMS projects that 12.2 GW of additional capacity, above that already installed in 2002, will be installed by 2010. The bulk of those installations are projected to be in the industrial sector. The NEMS analysis for cogeneration is based on payback calculated from average prices, and is documented by the Energy Information Administration.

Cumulative Capacity Additions (GW)	2007	2010	2015	2020	2025	2030
Industrial Total	8.00	11.8	15.2	19.6	23.6	27.4
Industrial- Natural Gas	6.35	9.45	12.4	16.4	19.9	23.2
Industrial- Coal	0.50	0.50	0.40	0.40	0.35	0.35
Industrial- Oil	0.01	0.02	0.03	0.04	0.05	0.07
Industrial- Biopower	1.15	1.85	2.35	2.80	3.30	3.80
Commercial	0.30	0.40	0.50	0.95	1.25	1.50
TOTAL	8.30	12.2	15.5	20.5	25.0	29.0

Table 2. Cumulative CHP Capacity Additions above 2002 baseline for GPRA 2003

Electricity generation displaced from the grid is then calculated from this capacity using the following procedures. Both industrial and commercial energy balance calculations are performed, as these sectors have different energy efficiencies and prices. The energy consumed on-site with CHP is netted out against the energy that was used on-site prior to the implementation of CHP and the energy supplied in the form of electricity by the grid. The energy content of the displaced electricity is calculated using both electricity generation and end-use consumption heat rates. The latter is used to calculate the net primary energy displacement and cost savings, as this is the amount of energy that is displaced at the site. However, since the emissions displaced are produced not on site, but rather at the point of generation, the energy content of the electricity at generation must be calculated as well to realize the true net emissions savings. Emissions from CHP systems using natural gas are generally low – if hydrogen were explicitly considered in the emissions calculations, the projects for emission displacement would be even greater than those presented here.

The model then projects the energy cost savings, carbon emissions savings, and other benefits realized based on these figures, in accordance with the GPRA FY2003 guidance document.

A determination of the fuel-use of these technologies was also required in order to calculate the benefits from CHP introduction. Industrial applications are split between natural gas, coal, oil and biomass. Natural gas is by far the most dominant fuel choice, and is expected to gain an even greater share in the future, rising from 79% in 2007 to 85% in 2030. Industrial biomass cogeneration represents about 15% of total CHP additions. The analysis assumes 100% natural gas use for commercial applications.

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Appendix A. Market Segmentation

The market segmentation used in the analysis is shown in Figure A1. At the highest level, the market was divided into: 1) Grid-Side Systems -- systems that are on the grid side of the meter, and owned by utilities or other power suppliers; and 2) Customer-Side Systems -- systems installed at customer locations on the customer side of the meter.

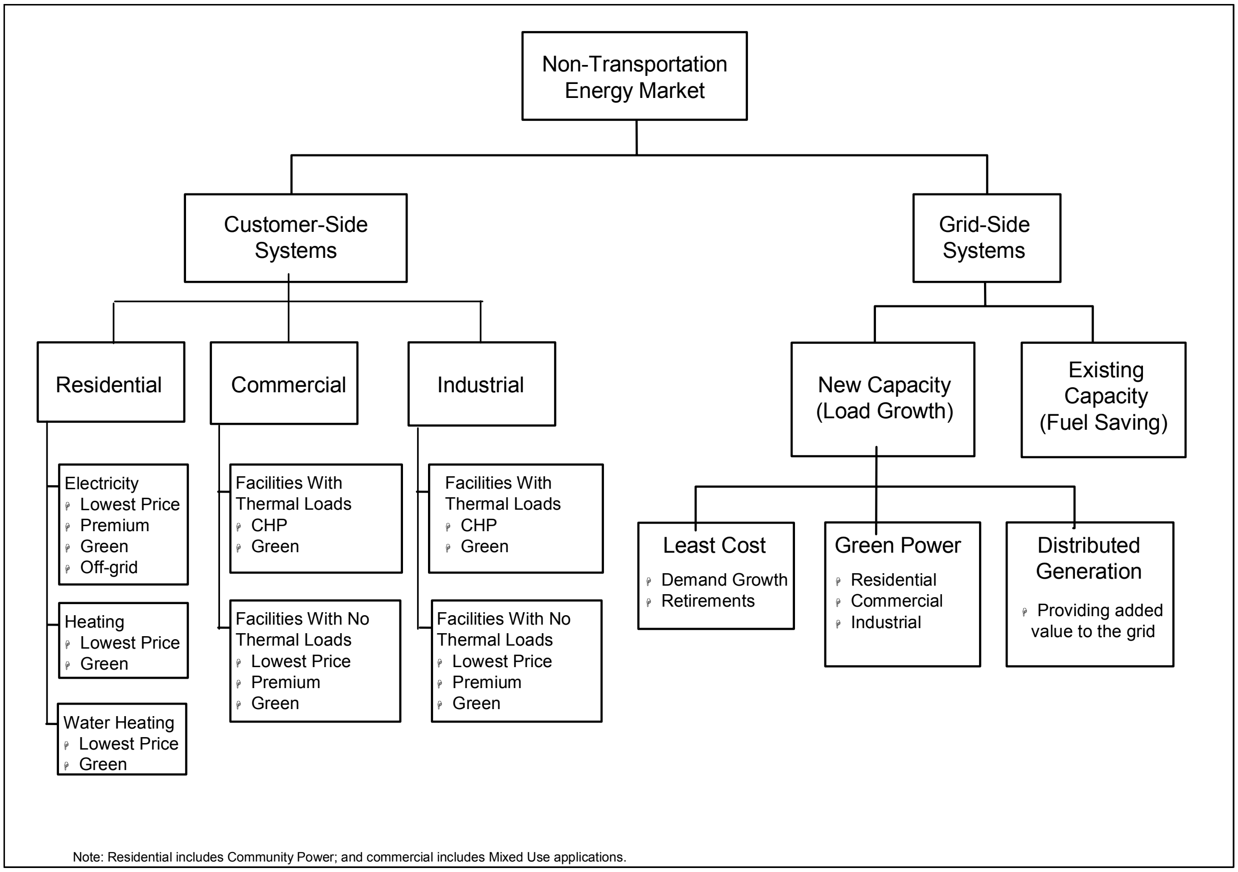

Figure A1. Market Segmentation of OPT Programs.

<u>Grid-Side Systems Segment</u>

The grid-side power segment includes power plants installed at either the transmission system level or at the distribution system level. This segment has traditionally been the realm of the regulated utility and, since 1978, the qualifying facility (QF). For modeling purposes, Grid-Side Power was subdivided into two sub-elements -- new capacity and existing capacity. The former considers capacity additions required to meet demand growth and those required to satisfy capacity needs created by plant retirements. The existing capacity subsegment consider those instances when the costs of generation from either biomass co-firing or intermittent wind and solar plants are less than the variable costs of operating existing plant capacity. This is commonly termed the fuel-saving market.

New capacity requirements have traditionally been met by new plants installed as a result of utility planning processes. As electricity markets are restructured, new business arrangements for satisfying this demand will emerge, but this segment will continue to represent the bulk of the capacity and generation supplied to the grid. (In the evolving restructured market, “merchant” power plants will also be constructed that compete with less-efficient, more-costly existing capacity. The analysis assumed that merchant renewable plants will be few in number.) This least cost subsegment could, in principle, be satisfied by capacity installed at either transmission system level voltages or at distributed system voltages. The former will typically be larger systems (central station) and the latter will be smaller systems (dispersed throughout the distribution system). The analysis characterized the costs and performance of both large and small plant sizes and allowed them to compete as appropriate for new capacity requirements. It must be emphasized that in this subsegment the distribution-level systems are installed solely for their capacity and generation value. No additional benefits to the utility system are considered. Plants that offer such "distributed benefits" are explicitly included in the Distributed Generation subsegment (see discussion later).

Green Power is a term that describes the public's apparent interest in renewable generation as a responsible alternative to conventional energy supply. Table B1 shows what technologies were considered in the analysis of the Green Market analysis. The definition of which technologies qualify as being eligible to use in this marketplace was narrowly drawn to best reflect green e definitions. Customers can acquire *Green Power* either by purchasing it from a supplier, or by installing their own system. The market segmentation reflects both of these options. (Note -- the customer-side green subsegment, shown in Figure A1, was explored for photovoltaics and biomass cogeneration.) The *Green Power* subsegment of the Grid-Side Power segment is an evolving market that the analysis examined explicitly. It included two closely related marketing mechanisms for offering end-users the opportunity to purchase power that is generated by environmentally responsible means. *Green Pricing* is a mechanism by which regulated electric utilities have an approved tariff under which their customers can chose to pay additional monies to ensure that green electricity will be provided by their utility. However, more generally under a deregulated utility supply system, *Green Marketing* programs will include a variety of opportunities through which customers pay a premium to ensure that they are "buying" electricity from green sources.

The *Distributed Generation* subsegment of the Grid-Side Systems segment is also a specialized market. The Distributed Generation portion of the analysis accounted for those site-specific instances where small-scale generating systems or storage systems provide cost-saving benefits to the grid that go beyond pure capacity and generation values. These system benefits are often described as being valuable in supporting weak elements of the distribution system, or as helping alleviate pressures on the distribution system due to rapid load growth on parts of the system. Because this subsegment is just now developing, and only small amounts of capacity, in the context of national needs, are being installed, no energy or emissions displacement benefits directly attributable to distributed systems were projected.

<u>Customer-Side Systems Segment</u>

The Customer-Side Systems segment was analyzed in three sub-segments: residential, commercial, and industrial, including cogeneration.

Elements of the residential segment include: 1) systems that are owned because they are less-expensive than purchased alternatives (the lowest price element); 2) systems that offer added value to the owner beyond the basic commodity value of electricity, e.g., a desire to have reliable power independent of grid supply -- this value-added element could also have a green component (the value-added element); 3) systems that are green and are purchased for that reason, despite the fact that they are more expensive (the green element); and 4) systems that meet off-grid needs where conventional supplies are either unavailable or prohibitively expensive (the off-grid element).

The commercial and industrial subsegments mirror the residential, although there may be fewer opportunities for the off-grid market element. Cogeneration is defined as a separate element in the industrial subsegment because it is analyzed as a distinct market and was modeled in the National Energy Modeling System (NEMS) Industrial Demand Module.

Appendix B. Overview of Modeling Framework

Table B1 shows the suite of models and analytical tools that OPT used for the analysis. The five Renewable Energy Technology Programs were analyzed using NEMS and the Green Power market Model. For PV and biopower, additional exogenous modeling was required. The remainder of the programs all required analysis tools to be developed specifically for that program. These tools are described in this report in the various program chapters.

Table B1. Overview of OPT Analysis Approach

OPT Program Element	**NEMS**	**Green Power Market Model**	**Exogenous Models**
Solar Buildings			
Photovoltaics			
Concentrating Solar Power			
Biopower			
Wind			
Renewable Energy Production Incentive (REPI)			
Solar Program Support (Competitive Solicitation)			
Geothermal			
Hydrogen			
Distributed Energy Resources			
High Temperature Superconductivity			

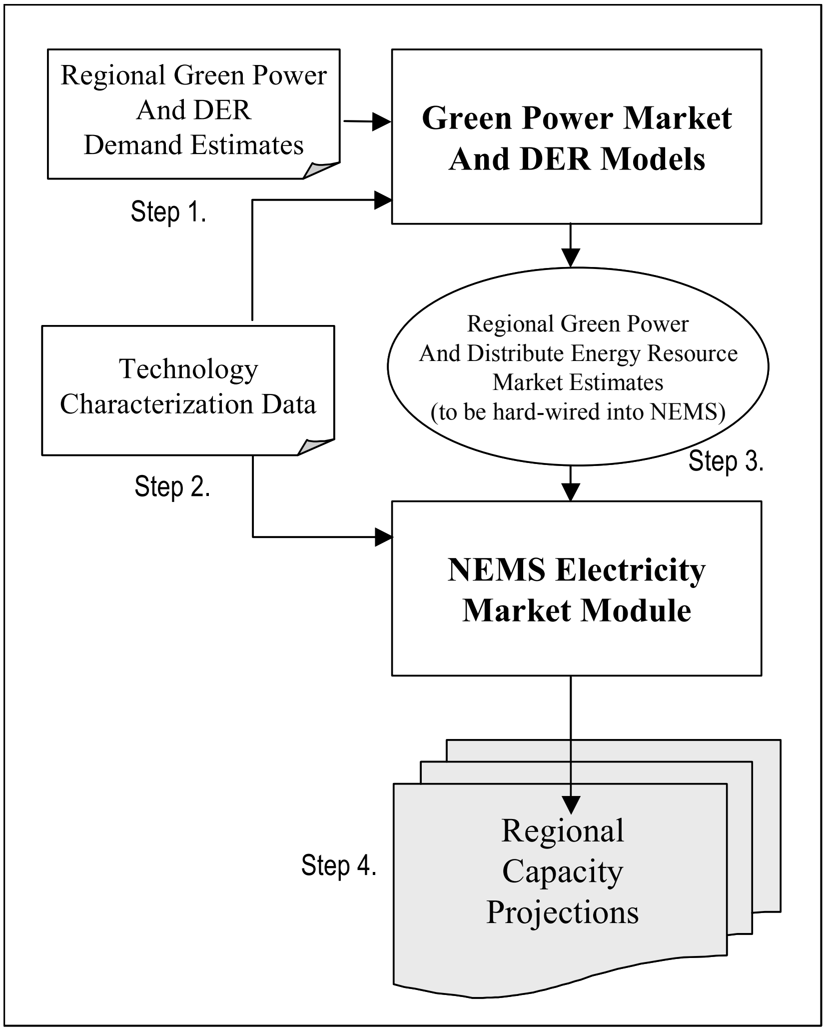

Figure B1. Renewable Modeling Framework

The benefits analyses for the five renewable generating technologies and the four distributed energy resource programs are conducted conceptually as shown in Figure B1. This is an integrated combination of NEMS, and both the Green Power Market Model and Distributed Energy Resources (DER) Model. The analysis begins with estimates of the total potential green power market , and separately, the total DER potential (Step 1). This value is an upper bound which takes many years to achieve. Both models forecast much of the anticipated growth in these areas to the later years of the analysis. The Green Power Market Model does not predict that each region of the country will reach the saturation point for customer participation, 30%, until 2040. Likewise, the DER model shows the bulk of capacity additions occur in the out years of the analysis. These models combine the projections for total green power and DER market demand with the cost and performance projections of the *Renewable Energy Technology Characterizations* and OPT estimates of DER technologies (Step 2). The models produce a regional estimate of green power additions, by technology for the Green Power Market Model, and sectoral estimate of DER additions, by fuel type (Step 3). These regional and sectoral additions are explicitly included in NEMS as planned capacity. This capacity has the effect of reducing total future demand growth and causes NEMS to build less capacity, both conventional and renewable, in the future. The NEMS analysis produces regional projections of future electricity capacity, including future builds of renewable plants (Step 4).

Appendix C. Green Power Market Model

Introduction

The Green Power Market Model (GPMM or the model) identifies and analyzes the potential generating capacity additions for electricity production that will result from "green power" (either green marketing or pricing) programs, which are not captured in the "least-cost" analyses performed by the National Energy Modeling System (NEMS). Princeton Energy Resources International, LLC (PERI) originally constructed the GPMM in August and September 2000, as a sub-module, with the results hard wired into NEMS as planned capacity. This year's model, based in Microsoft Excel 97, is consistent with efforts from last year, with several changes documented herein. The changes that have been incorporated for this year's analysis are a more detailed and regionalized set of assumptions for electricity market restructuring from the *Growing the Green Power Market: Forecasting the Impacts of Customer Demand for Renewable Energy*, a recent report by Blair Swezey et al. completed for the National Renewable Energy Laboratory (NREL). (4) These assumptions include the dates for initiation of market restructuring as well as the assumed green power penetration rates, a change in the time periods tracked in the analysis, and a new method for calculating funds from program participants.

Green technologies are marketed as energy production in a cleaner, safer, and renewable fashion. However, the definitions of what constitutes a green technology and how it should be marketed are quite ambiguous in the early deregulation arena. Several agencies and organizations have identified this ambiguity and have offered suggestions. The American Wind Energy Association's (AWEA) *Principles of Green Marketing* was developed in an "effort to foster a credible market in environmentally-preferable electric services… that results in meaningful changes in the electric system as whole." (2) Lawrence Berkeley National Laboratory's (LBNL) *Green Power Certification* report points out the need for creation of certification programs to validate retailers' claims of providing green energy (1). Several organizations have begun to certify green power marketing claims and sales agreements in areas with competitive access to power available, including the Center for Resource Solutions' (CRS) Green-e program, the Scientific Certification Services' (SCS) Environmentally Preferable Power program, and the Environmental Resource Trust's EcoPower program.

The Green Power Network, a part of the US Department of Energy (DOE), defines both green power and green power marketing on their web page. It states that the "essence of green power marketing is to provide market-based choices for electricity consumers to purchase power from environmentally preferred sources. The term "green power" is used to define power generated from renewable energy sources, such as wind and solar power, geothermal, hydropower and various forms of biomass." (3)

For purposes of this analysis, the term "green marketing" refers to selling green power in the competitive marketplace, in which multiple suppliers and service offerings exist. Green marketing programs occur in restructured markets that were formerly served by either investor-owned utilities (IOU) or public utility companies (PUC) and give the customer the option of paying a market price (higher if necessary) to ensure that their electricity demand is met by green power. (3) "Green pricing" programs, on the other hand, represent the programs sponsored by utilities that give customers the opportunity to pay extra to support the development and operation of green power sources. Those utilities, both IOUs and PUCs, which remain regulated in our analysis have the option of providing "green pricing" programs.

The Model

Technologies

The model projects additional capacity and electricity generated from green technologies for the periods 2003 to 2007 and 2008 to 2010, and then five-year periods to 2030. Sixteen individual technologies, comprising five technology types, were selected as both green and commercially viable for this analysis. The technologies, listed below, can be grouped into categories based on both the availability of power, Dispatchable or Intermittent, and on resource use. These are:

Dispatchable:

1) Biopower:	- Direct-Fired (Steam Turbine) Biopower
	- Biomass Gasification
	- Landfill Gas
2) Geothermal:	- Flash Geothermal
	- Binary Geothermal
	- Hot Dry Rock
3a) Concentrated Solar Power:	- Solar Thermal Trough
	- Solar Thermal Dish- Hybrid
	- Solar Central Receiver

Intermittent:

3b) Concentrated Solar Power	- Solar Central Receiver (Intermittent)
	- Solar Thermal Dish- Stand Alone
4) Photovoltaics:	- Residential PV (Neighborhood)
	- Central Station PV (Thin Film)
	- Concentrator PV
5) Wind:	- Wind Turbines

Although the model was initially designed to distinguish between dispatchable and intermittent technologies, more recent versions of the model exclude this distinction. The original distinction was accomplished by adding an extra cost to intermittent technologies associated with "firming up" the technologies' ability to provide a constant power supply. Generally, the additional capacity needed to maintain stability of power comes in the form of diesel generators or gas turbines, for which the model calculated these additional costs. However, since green power programs only guarantee that a certain percentage of total kilowatt-hours generated will come from green sources over the course of a year, the developers of new green power do not have the incentive to include back-up generation to provide a continuous source of power. Developers are assumed to build the sites in least cost fashion (without back-up) and take the "green" electrons when and from where they are able. The "firm up" costs are now set to zero in the model, which effectively removes the competitive advantage, and therefore the distinction, of dispatchable sources over intermittents.

Regions:

The model is composed of regional segments, used to capture differences in the costs of competing technologies, resource availability, levels of participation in voluntary green marketing programs, and electricity demand by sector. PERI has elected to use US Census regions as the breakdown, as the availability of regional data for the model often takes this format. Eight regions (South Atlantic and East South Central have been combined) are modeled independently, and then summed to produce national results (see Appendix A). The regions for this analysis are 1) New England, 2) Middle Atlantic, 3) East North Central, 4) West North Central, 5) South Atlantic and East South Central, 6) West South Central, 7) Mountain, and 8) Pacific.

This regional breakdown is different from the regional divisions of NEMS, however. In order to be explicitly included in NEMS, the eight regional capacity projections must be converted to thirteen divisions used in NEMS (see Appendix B). The NEMS divisions are based on the North American Electric Reliability Council's regions. The names of these regions, and the conversion formulas from the census region breakdown are documented in the model.

The state-by-state restructuring and penetration assumptions taken from the *Growing the Green Power Market: Forecasting the Impacts of Customer Demand for Renewable Energy* (the NREL report) are summed across these regions, and are pro-rated based on the loads of the electric market in each state compared to the region as a whole.

Assumptions:

A number of new assumptions were included in this year's analysis from the NREL report, primarily the rates of restructuring and market participation rates on a state-by-state basis (see Appendix C). In order to more accurately reflect the fairly high degree of uncertainty surrounding electric market restructuring, especially in light of the unstable markets seen in California and the rest of the country, this report identifies both a high- and low-growth set of assumptions. PERI and NREL have agreed to use the high-growth case for inputs into the model as this set employs the technology cost data from the DOE/EPRI report, Renewable Energy Technology Characterizations (TC), which is the same data used in our model.

The high-growth case also assumes that restructuring proceeds in most states with little or no delay, market rules are conducive to competition and customer switching, and customer understanding and participation continues to increase. Specific assumptions from the high-growth scenario include:

- IOU restructuring: States already open to competition remain open and retail choice continues as scheduled.
- PUC restructuring: Starts at 2.5% in the 3rd year after IOU restructuring commences, and increases to 20% by the 10th year.
- Access to Green Power: In regulated markets, starts at 5% and increases 60%, while in Competitive markets 100% is assumed to be open.
- Green Power Market Penetration: In regulated markets, participation starts at 0.75% for residential customers in 1st year, increasing by 0.75% annually to 7.5% in the 10th year, while in competitive markets, participation starts at 1% and increases to 10% in the 10th year. Non-residential customers are a constant 25% of residential participation in both regulated and competitive markets. (4)

The results of the model reported here are based strictly on the high-growth set of assumptions, however a qualitative description of the impacts of using the low-growth assumptions is given at the end of this report.

Electricity markets are now deregulated and openly competitive in several states: California, Connecticut, Massachusetts, Maine, Rhode Island, Pennsylvania, Maryland, Montana, and New Jersey. A number of other states, including Arizona, Texas, New Hampshire, New York, Delaware, the District of Columbia, Illinois, Ohio, and Michigan, have restructuring legislation or executive orders pending that will phase in competition over the next two years. As states begin to restructure their markets, it is assumed the pace of restructuring will vary from state to state. But with in five years of deregulation, it is assumed that 100% of the IOUs markets will have active retail competition, except as dictated by existing legislation, including green marketing programs. To this extent, all states are assumed to restructure at least a portion of their electric markets by 2007. (4)

On the other hand, green pricing is an optional utility service that allows customers an opportunity to support a greater level of utility company investment in renewable energy technologies. Participating customers pay a premium on their electric bill to cover the extra cost of the renewable energy. Green pricing implies a continued regulated arena in which an optional fee is paid by customers to promote their utility's development of renewable energy technologies. The assumptions of the NREL report incorporated in our model suggest that a portion of those utilities still regulated in each state will offer green pricing programs. As more and more markets are restructured, the green pricing programs are converted to green marketing programs. However the customer participation levels achieved under green pricing programs are assumed to remain at a constant level the first year under deregulation, with the incremental gains of deregulated markets starting in the following year. Another important assumption incorporated into our model is that restructuring never fully includes all of the PUCs, nor do green pricing programs ever enter into all of the still regulated utilities. From these assumptions, it can be seen that at least some of the customers in each state never gain access to green power markets, but the regional percentage of all customers with access to green power programs grows to 77%-96% in the out years of the analysis.

A second set of assumptions taken from the NREL report deals with customer participation in green power programs. The assumption used in last year's analysis that 30% of eligible residential customers would eventually enroll in these voluntary programs was both regionally varied and reduced overall in this year's analysis to more accurately reflect customer participation rates in existing programs. The customer participation rates reach 9-14% in the out years of the analysis, a reduction of more than 50% from last year's assumptions. The participation rates for the commercial and industrial sectors have been reduced as well, although both are still tied into the residential participation rates. Commercial and industrial customers' participation rates are assumed to be 16.7% and 8.3%, respectively, of their residential customers counterparts, down from the 50% and 25%, respectively, assumed in last year's analysis. Another key assumption is that all customers continue in the programs once they have joined. Table 1 shows the assumptions and calculations of regional customer participation rates for green marketing programs.

Table 1. Regional Participation Rates in Green Power programs

	2000	2002	2007	2010	2015	2020	2025	2030
New England	1%	2%	7%	10%	13%	14%	14%	14%
Middle Atlantic	0%	3%	7%	10%	14%	14%	14%	14%
East North Central	0%	0%	5%	8%	12%	13%	13%	13%
West North Central	0%	0%	2%	4%	8%	9%	9%	9%
South Atlantic/East South Central	0%	0%	2%	5%	8%	10%	10%	10%
West South Central	0%	0%	3%	6%	10%	11%	11%	11%
Mountain	0%	0%	3%	7%	11%	12%	12%	12%
Pacific	0%	0%	2%	5%	8%	11%	11%	11%

Another important assumption that has been modified for this year's analysis is how the payment is made for participation in these programs. A range of payment devices currently exists in green power programs underway, with some programs charging an additional amount per kilowatt-hour, a fixed amount each month, or a percentage of the total bill. PERI has chosen to use the percentage of the total bill, assumed to be at 10%, to more accurately show the regional energy price variation. In years past, the model used a fixed payment per month method to represent all programs, with amounts of $6, $96, $408 for the residential, commercial and industrial sectors, respectively. However, this fixed price method does not reflect the regional energy price variability, nor is it the most commonly used method in current programs. As the model already incorporated both the average regional electricity use and regional electricity prices, PERI was able to calculate the amount of funds generated from these programs.

The model uses only the dollars from customers joining green programs each year to build new capacity, as money from customers who have joined in prior years is assumed to continue to finance projects built in those years. Another key assumption is that all of the money collected from these programs will go towards building additional capacity.

An important modeling assumption allows the model to build multiple competing technologies in a region, not only the least cost alternative. This approach avoids so-called knife-edge choices, and recognizes that single point estimates of data actually represent a range of values. The percentage apportioned to each technology is inversely related to its first-year cost of energy (FY COE) through a logit function, consistent with NEMS modeling procedures. The spread of the distribution is dependent upon a scaling factor, lambda, which often ranges from 0 to 15. As this factor increases, the lower cost technologies receive a higher percentage of the total distribution. PERI has chosen to set this factor at 3.2. A small sensitivity analysis was conducted ranging lambda from 1 to 11 with minor impacts (less than 10%) on the resulting totals.

The final set of assumptions deals with the creating regional distinctions in the model by varying the resource potential of the technologies. This was done both throughout the entire nation and in subsets of the regions, depending on the specific technology characterizations. Landfill Gas, for example, is limited nationwide by the availability of an economically viable resource base. To account for this, a 70 MW capacity limit was instituted in each region.

For technologies such as CSP and Geothermal, resource-based regional distinctions were introduced via adjustment factors (AF). For each technology, a base capacity factor (CF) was taken from the TC report. (5) The AFs were then applied to the base CFs in order to create the regional distinctions. An AF greater than one implies that the resource is more prevalent in that region, and therefore the cost of producing electricity from that technology would lower. The AFs are based on available resource levels as determined from resource maps in the TC document. The AFs for each region, and the subsequent regional CFs are noted in Appendix A. Certain technologies are excluded from regions, due to prohibitively high costs or the absence of a resource base, by setting their respective AFs to zero. Table 2 documents these exclusions.

Table 2. Regional Exclusion of Green Technologies

Technology	Region 1	Region 2	Region 3	Region 4	Region 5	Region 6	Region 7	Region 8
Direct-Fired Biopower								
Biomass Gasification								
Landfill Gas								
Flash Geothermal	X	X	X	X	X	X		
Binary Geothermal	X	X	X	X	X	X		
Hot Dry Rock	X	X	X	X	X	X		
Solar Thermal Trough								
Solar Thermal Dish Hybrid								
Solar Central Receiver	X	X	X		X			
Residential PV (Neighborhood)								
Central Station PV (Thin Film)								
Concentrator PV								
Wind Turbines					X			

X- indicates regions where technology is assumed to be unavailable.

Landfill gas is restricted to a 70 MW addition to each regional capacity for each time period, down from 115 MW in the 1999 model. Geothermal technologies have been restricted compared to prior efforts, given potential to penetrate in the Pacific and Mountain regions only. CSP technologies were generally allowed to compete more widely in the 2001 model. In 1999, trough systems were assumed viable in all regions of the country, although significant insolation level penalties were assumed for many regions. Central receiver technologies were assumed to be applicable only to the southern regions of the country. In 2001, the central receiver technology can now compete in the W.S. Central, W.N. Central, Mountain, and Pacific regions. Hybrid Dish and trough CSP technologies are now fully competitive in all regions.

Inputs:

The GPMM uses the Annual Energy Outlook 2001 (AEO01) projections for electricity demand in the residential, commercial and industrial sectors. (6) The NREL report, *Growing the Green Power Market: Forecasting the Impacts of Customer Demand for Renewable Energy*, was used to determine both the availability and customer participation in green power markets. (4) PERI estimates were used for various other modeling assumptions, including the dropout percentage and lambda values employed. Inputs of the technology characterizations, including capital, fuel and O&M costs, capacity factors were taken from the Renewable Energy Technology Characterizations document. (5)

Comparison of 2000 and 2001 models:

This section presents a comparison of results of the GPMM for the past two years. The differences in predictions from 2000 to 2001 model runs result from a number of changes that were made to the model's assumptions this year. Most of the changes reflect the most up to date information on the electricity market restructuring and green power market participation.

The revenues assumed to be available from green marketing programs in the 2001 (FY2003) model are significantly lower than those in the 2000 (FY2002) model. This results in lowered capacity additions throughout the entire timeframe of the analysis. A key contributor to this reduction was that the assumed customer participation rates in green power programs were scaled back significantly. Whereas, in years past, the maximum participation rates achieved were 30% in all regions, this has been scaled back to 9% to 14% based on regional variations.

Other less significant factors also contribute to the reduction in capacity additions. First the housing, commercial and industrial sector demand inputs have been revised. Although, the change in the surcharge method for participation in green marketing programs, from a fixed price payment to a 10% premium on the total electricity bill, actually increases the revenues from each customer, the overall impact of reducing the availability of green power access and the customer participation in these programs substantially decreases the amount of money available to build new plants.

Finally, the last set of changes deals with the time frames of the analyses. The 2001 model has switched the initial time frames of the analysis from 2002-06 and 2007-10 to 2003-07 and 2008-10, with five- year periods extending to 2030.

Results:

The results of this year's model have been compared to results from the 2000 model in order to show the impacts of changes in assumptions, input parameters, and algorithmic computations. Table 3 shows this comparison based on technologies utilizing a common resource.

Table 3. Comparison of 2000 and 2001 Model Results

Technology	**2010**		**2020**		**2030**	
(Cum. MW)	2001 run	2000 run	2001 run	2000 run	2001 run	2000 run
Biopower *	250	294	551	1,052	617	1,645
Geothermal	262	219	695	740	821	1,228
Concentrating Solar Power	209	167	609	1,076	703	1,732
Photovoltaics	143	115	667	1,248	962	2,184
Wind	2,818	1,194	4,463	6,928	4,842	10,626
Total RETs	**3,419**	**2,760**	**7,256**	**11,044**	**8,299**	**18,415**

* Biopower values exclude landfill gas installations.

Description of Low-growth Assumption Impacts:

The low-growth scenario explored in the NREL report is far less aggressive in terms of customer participation and market restructuring than the high-growth case that was used for this analysis. The low-growth assumptions characterize a scenario in which the introduction of customer choice is delayed by a number of years, the market rules are not conducive to competition and do not promote customer switching, consumer understanding and customer participation rate growth slows considerably, and technology improvements and cost reductions for renewable technologies stagnate. Specific assumptions from the low-growth scenario include:

- IOU restructuring: States already open to competition remain open, however states that are scheduled to undergo restructuring are delayed by two years.

- PUC restructuring: Starts at 0.5% in the 3rd year after IOU restructuring commences, and increases to 4% by the 10th year.
- Access to Green Power: In regulated markets, starts at 5% and increases 27.5%, while in Competitive markets 100% is assumed to be open.
- Green Power Market Penetration: Starts at 0.25% for residential customers in 1st year, increasing by 0.25% annually to 5% in the 20th year. Non-residential customers are a constant 10% of residential participation.

The impacts of the low-growth scenario on the results of the model are a substantial reduction in the amount of customer access and participation in green power programs. Due to this, the amount of money collected from these programs is decreased, resulting in lower level of installed capacity for generating technologies. Unlike the results of the high-growth scenario, the low-growth assumptions lead to a reduction in capacity installations over the next decade in comparison with the 2000 model results. However, both the high- and low-growth assumptions decrease the capacity builds in the final two decades of the analysis.

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3) Green Power Network. 2000. *Welcome to the Green Power Network!* Web document: http: www.eren.doe.gov/greenpower/html/.

4) Swezey, Blair, R. Wiser, M. Bolinger, and E. Holt. 2001. *Growing the Green Power Market: Forecasting the Impacts of Customer Demand for Renewable Energy*. National Renewable Energy Laboratory, US Department of Energy. NREL/TP-620-30101.

5) US Department of Energy/Electric Power Research Institute. 1997. Renewable Energy Technology Characterizations. Office of Utility Technologies, Energy Efficiency and Renewable Energy, US Department of Energy. EPRI- TR109496.

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Appendix D. Support Documentation for Baseline Revisions

January 30, 2002

To: Tina Kaarsberg, Paul Trottier
From: Tom Schweizer, Jim McVeigh

Subject: Reconciling Strategic Plan and GPRA2003 Baselines

Over the past several months, we have provided capacity data for two purposes. The first is the FY03 GPRA process, which began last Spring. The second is the EE Strategic Plan (SP) process which began in the Fall. It has been difficult to use exactly the same information for both, as will be described in this memo. In addition, we have provided information for the GAO audit that is comparing OPT GPRA metrics to AEO projections.

The concept of baseline capacity is ambiguous. For GPRA, the baseline value is actually a projection of capacity that will be installed at the end of 2002, and not statement of current reality. That projection is provided by NEMS, and occasionally does not match reality very closely.

For the EE Strategic Plan, the request was for a baseline of 2000/2001. The value provided for that baseline should be what is actually installed. Therefore, the GPRA baseline and the SP baseline will necessarily be different. That difference is increased by the fact that the SP baseline includes biopower cogeneration, whereas the GPRA baseline does not. The SP baseline also includes non-grid PV systems, whereas that capacity has never been explicitly accounted for in GPRA.

The following table provides values for both activities. It also provides a breakdown of 2000 capacity versus 2001 capacity. Where the values are these same, there were essentially no significant additions during 2001.

Table 1. Capacity Baselines

Technology	GPRA 2003/GAO Auditor	EERE Strategic Plan	
Reference Year	End of 2002	2000	2001
Geothermal	2.93	2.93	2.93
Biopower	1.6	10.0	10.0
CSP	0.35	0.35	0.35
PV	0.03	0.316	Not available
Wind	3.8	2.55	4.26

(Tina noted yesterday (1/29/02) that there was a conflicting set of baseline data that PERI had provided on January 11, 2002, in a file called *Revised to Tina.XLS*. Upon tracking that file down, it became clear that the baseline data in it were from the FY02 GPRA process. That file is the only place we have located that mistake, and all current working documents are correct and in accordance with the Table above.)

Referring again to the Table, there are a number of differences that should be highlighted:

First, the SP biopower figures include an estimate of cogeneration systems, which have never been included in the biopower GPRA benefits calculations. The value of 10 GW is drawn from an ADL report, *Aggressive Growth in the Use of Bio-derived Energy and Products in the United States by 2010*. As might be surmised, it is a rounded value and not an actual count of systems.

We have included off-grid PV capacity in the SP baseline, which is an order of magnitude larger than the on-gird capacity that NEMS projects. We may wish to add off-gird PV to the GPRA analysis for FY2004.

For wind, there was significant growth in 2001. Therefore, it is important to clarify what year the SP baseline is being provided for. It would seem that end-of-2001 would be the right choice.

Spreadsheet Provided to GAO Auditors

In early submissions to GAO, OPT provided data on installed 2000/2001 capacity. Since that time GAO's focus has shifted away from program goals toward program projections. In keeping with that shift, it now makes more sense for the baseline data to be either the same as the GPRA baseline, i.e., the end-of-2002 projection, or to be the NEMS Reference Case capacity for 2000. We suggest sticking with the GPRA baseline to avoid introducing additional data into the discussion.

In an earlier submission, a 2000/2001 baseline for wind of 3.8 GW was provided to the GAO auditors. That figure is in fact the end-of-2002 GPRA baseline and should not have been interpreted as the 2000/2001 baseline. Table 1 provides the correct interpretation for this value and also provides the other values.

A 2000/2001 baseline for wind of 3.8 GW was provided previously to the GAO auditors. That figure is in fact the end-of-2002 GPRA baseline and should not have been interpreted as the 2000/2001 baseline. In keeping with the SP baseline guidance, the 2000/2001 wind baseline for the auditors should have been either 2.55 GW or 4.3 GW. We need to decide which to use. (Ironically, the end-of-2000 and end-of-2001 values straddle the 3.8 GW value that the auditors were provided.)

From my discussion on 1/17/02 with Bruce and Charlie, it is clear that their primary interest is in the cumulative 2020 projections, not the baselines. We need to pick one baseline or the other (SP or GPRA) and use that consistently in communications with them. I suggest the GPRA values because of their relevance in comparing to AEO projections. In all cases, we will always provide GPRA projections that include the baseline.

Revised GAO Files

1) We have revised the spreadsheet of capacity projections. It now includes 2001 actual installed baseline data, and projections for 2010, 2015, and 2020 for both the GPRA (high) and GPRA (low) scenarios. (See file gaodocu6.xls)

2) The memo prepared 1/18/02 entitled "Overview of Capacity Projections and Modeling Assumptions for the OPT" does not discuss baseline questions and has been reviewed by OnLocation for its correct interpretation of the EERE-sponsored sector-only analyses. That memo can go forward without change. (see file gaoopta1.doc)

3) Answers to questions can go forward unchanged (see file gaooptc1.doc).

Overall Comments

While we believe that data consistency is essential in all that we do, it does not appear that the baseline values for the GPRA/GAO and SP exercises can be, or even need to be, identical. We just need to be confident that they emanate from the same analysis and are consistent. We believe the baseline data that the Table provides should be adopted, selecting end-of-2002 for GPRA and GAO, and 2001 for the Strategic Plan.

Appendix E. Support Documentation for GAO Review

TO: Bruce Skud and Charlie Hester, GAO
From: Tina Kaarsberg, Susan Holte, Office of Power Technologies (OPT)
RE: Overview of Capacity Projections and Modeling Assumptions for the OPT

Summary: This memo provides all the available information requested by Charles Hester in his January 4th email which included a file called #336628 v1 - OPT SAMPLE MATRIX.doc" (attached). We provide the same information here in a more readable format that allows for extensive references and explanation that you requested verbally in telephone conversations on January 25th, 2002 and in December 2001.

Overview: The Office of Power Technologies (OPT) develops projections of program benefits for reporting under the Government Performance and Results Act (GPRA). Because of uncertainties inherent in market projections, especially for renewables that currently have a very small baseline, OPT now reports a range of results in its response to the GPRA requirements. The upper and lower numbers in the range are arrived at through different means. The "GPRA (low)" numbers are strictly NEMS model results. The "GPRA (high)" numbers also include offline analysis detailed in the **Other Market Considerations** section below. The OPT results are an alternative to EIA's projections, as published in the *Annual Energy Outlook 2001*. A primary difference between the GPRA and EIA projections is that the OPT projections assume that the OPT research programs achieve significant success in improving the cost-effectiveness of renewable electricity generating technologies.

The technologies that are included in the analyses described here are listed in Table 1.

Table 1. Description of Included Technologies

Geothermal	Hydrothermal systems in GPRA and AEO; Enhanced Geothermal Systems (EGS) in GPRA
Biopower	Direct-fired, gasification, and co-firing systems. Cogeneration systems are not included.
CSP	Power tower, trough, and dish-engine systems.
PV	Central station and distributed residential systems; off-grid systems are not included
Wind	Utility-scale systems; off-grid systems are not included

Table 2 compiles the results of four projections, and contrasts the assumptions and methods used in their derivation.

Table 2. Comparison of OPT Capacity and Projections for 2020

2020 Capacity Projections (GW)				
	GPRA (low)	GPRA (high)	AEO2001 (Reference Case)	AEO2001 (High Renewables)
Geothermal	8.8	12.9	4.4	9.6
Biopower	5.0	12.1	2.4	3.2
CSP	1.0	2.4	0.5	0.5

PV	5.8	5.8	0.89	1.4
Wind	42.7	56.7	5.8	19
Note: capacity totals include capacity installed prior to 2001. OPT's usual reporting for GPRA does not include that capacity.				

2020 Generation Projections (billion kWh/yr.)				
	GPRA (low)	GPRA (high)	AEO2001 (Reference Case)	AEO2001 (High Renewables)
Geothermal	61	109	26	66
Biopower	30	86	22	23
CSP	4	16	1.4	1.4
PV	11	11	2.1	3.3
Wind	145	229	13	64

The four sets of projections, detailed above, differ for a number of reasons:

Production Tax Credit:

GPRA (low): The GPRA (low) case includes a 1-year extension, to 2002, for wind and closed-loop biomass.

GPRA (high): The GPRA (high) case includes a 1-year extension, to 2002, for wind and closed-loop biomass.

AEO2001 (reference): The AEO does not include a PTC.

AEO2001 (high): The AEO does not include a PTC.

Technology Cost and Performance Assumptions:

GPRA (low): Uses OPT-provided technology characterization data taken primarily from the *Renewable Energy Technology Characterizations*. However, also includes: 1) a significant revision to the wind characterization to account for new low wind speed technologies being developed for Class 4 resource areas; and 2) a reduction in the threshold price difference between coal and biomass fuels required for biomass cofiring.

GPRA (high): Uses OPT-provided technology characterization data taken primarily from the *Renewable Energy Technology Characterizations*. However, also includes: 1) a significant revision to the wind characterization to account for new low wind speed technologies being developed for Class 4 resource areas. Biomass co-firing is described in the section below on Other Market Considerations.

AEO2001 (reference): Uses EIA data, as described in AEO documentation.

AEO2001 (high): Uses technology projections similar to the *Renewable Energy Technology Characterizations*, but not including the new wind representation.

NEMS Modeling Assumptions:

GPRA (low): OPT has, over the past several years, raised a number of important concerns about how NEMS models the marketplace for renewables. These are described in a memo from Tina Kaarsberg (OPT) to Tom Petersik (EIA). However, for the GPRA (low) analysis, the only change made was to increase the limit on allowable penetration of intermittent renewables (i.e. solar, wind) in a region from 10% to 50%.

GPRA (high): same as GPRA (low)

AEO2001 (reference): Included a regional limit on intermittent renewables of 10% of generation.

AEO2001 (high): Included a regional limit on intermittent renewables of 10% of generation.

Other Market Considerations:

GPRA (low): A number of adjustments were made to the EE NEMS analysis, including:

Green Power: Results from the OPT Green Power Market Model (GPMM) were included in NEMS as planned additions. The Green Power market is characterized by non-price based decision-making, and, therefore, not captured by NEMS. The primary impact was for the lowest-price renewable technology, wind. The GPMM projects 4.5 GW of wind, of the total 7.3 GW, to be installed between 2003 and 2020 to meet demand for green power.

PV: The OPT PV projections include an additional 4.6 GW of capacity in 2020, which are attributable to the expected success of the Million Solar Roofs program.

GPRA (high): A number of adjustments were made to the OPT NEMS analysis, including:

Green Power: Results from the OPT Green Power Market Model (GPMM) were included in the NEMS runs as planned additions. The Green Power market is characterized by non-price based decision-making, and, therefore, not captured by NEMS. The primary impact was for the lowest-price renewable technology, wind. The GPMM projects 4.5 GW of wind, of the total 7.3 GW, to be installed between 2003 and 2020 to meet demand for green power.

Geothermal: The NEMS model includes only the 51 proven hydrothermal reservoirs. It does not yet include the additional (non-hydrothermal) geothermal resources that will be accessible using Enhanced Geothermal Systems (EGS). EGS is now a major thrust of the Geothermal Program, based on a 1990 assessment of the non-hydrothermal technical potential. Assuming moderate success in the EGS program, EGS systems were estimated to add 4.2 GW to the 2020 projection.

Biopower: Biomass resources modeled in NEMS did not take account of the additional resource potential identified in a recent report by Arthur D. Little. This report, *Aggressive Growth in the Use of Bio-derived Energy and Products in the United States by 2010*, was used to guide an upward adjustment of the projected capacity to 12.1 GW.

CSP: The NEMS model does not yet include the impact of new CSP program initiatives such as the Southwest Solar Initiative. Based on commitments to date and experience from the Million Solar Roofs program, an additional 1.3 GW is projected in 2020.

PV: The OPT PV projections include an additional 4.6 GW of capacity in 2020, based on known commitments for and therefore the expected success of the Million Solar Roofs program.

Wind: The cost of energy figures calculated by NEMS were adjusted in the model to match the energy prices reported in the *Renewable Energy Technology Characterizations*.

AEO2001 (reference): None

AEO2001 (high): None

Appendix F. Summary of GPRA-high and GPRA-low Results

Summary Comparison of Capacity Projections for GPRA (high) and GPRA (low)

GPRA (high) is OPT-sponsored analyses
GPRA (low) is EERE-sponsored sectoral run
Cumulative Capacity Includes the Capacity Installed at the End of 2002

	Installed Capacity at the end of 2002	Cumulative Capacity (GW) 2010	2015	2020	Notes:
Geothermal					
GPRA (high)	2.90	7.9	10.4	12.9	None
GPRA (low)		8.4	8.6	8.8	
Biopower					
GPRA (high)	1.60	8.6	10.4	12.1	Biopower excludes biomass cogeneration,
GPRA (low)		4.2	5.2	5.0	but includes co-firing.
CSP					
GPRA (high)	0.35	0.6	1.1	2.4	None
GPRA (low)		0.6	0.9	1.0	
PV					
GPRA (high)	0.03	1.4	3.6	5.9	PV baseline excludes 281 MW of off-grid installations at the end of 1999.
GPRA (low)		1.4	3.6	5.9	
Wind					
GPRA (high)	3.80	18.9	37.0	56.6	Note that NEMS projects less capacity to be installed
GPRA (low)		13.1	21.6	42.7	by the end of 2002 than were actually installed by the end of 2001.
Total GPRA (high)		37.4	62.5	89.7	
Total GPRA (low)		27.7	39.9	63.4	

Summary Comparison of Generation Projections for GPRA (high) and GPRA (low)

	Generation From Capacity Installed at the end of 2002 (billions of kWh/yr)	Annual Generation From Cumulative Capacity (billions of kWh/yr)		
		2010	2015	2020
Geothermal				
GPRA (high)	24	66	87	109
GPRA (low)		57	59	61
Biopower				
GPRA (high)	11	61	73	86
GPRA (low)		24	30	30
CSP				
GPRA (high)	1.2	3.3	6.9	16
GPRA (low)		1.9	3.1	3.8
PV				
GPRA (high)	0.1	2.5	6.5	10.9
GPRA (low)		2.5	6.5	10.9
Wind				
GPRA (high)	12	78	149	229
GPRA (low)		37	67	145
Total GPRA (high)	48	211	322	451
Total GPRA (low)		124	169	251

Appendix G. GPRA Data Call Fiscal Year 2003